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Impact of repeated cyclic production scheme on EUR in low-permeability reservoirs

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IMPACT OF REPEATED CYCLIC PRODUCTION SCHEME ON EUR IN

LOW-PERMEABILITY RESERVOIRS

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ABSTRACT

Productivity in low-permeability reservoirs declines quickly compared to conventional reservoirs. These tight reservoirs have very high initial oil production rates but as soon as the oil near the fractured area is recovered, the production declines rapidly making economic oil and gas production a challenge for the industry. This study investigates the impact of repeated shut-in/production cycles on the ultimate recovery of oil in such environments.

A reservoir model with multiple fractured horizontal well having 30 transverse fractures is created using CMG. Reservoir permeability is varied over the range of 0.000001 md to 10 md and shut-in/production cycles of 2-weeks, 1-month, 6-months and 1-year are introduced in a systematic way. Results of the simulations are presented as normalized recovery versus shut-in/production cycle duration, where normalized recovery is expected ultimate recovery (EUR) from any case divided by the EUR in the case without any shut-in/production cycle.

A second reservoir model having two multiple fractured horizontal wells adjacent to each other is also created. This model simulates a field scenario with multiple wells and proposes a way of introducing this production technique in an industry accepted form, which enables continuous production along with the added benefits from shut-in/production cycles.

Results from this work show that ultimate recovery of oil can be improved in some cases, by introducing systematic shut-in/production cycles.

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1. INTRODUCTION

Unlike conventional reservoirs, the productivity in low-permeability reservoirs declines quickly making economic oil and gas production a challenge for the industry during low price environments. These tight reservoirs have very high initial oil production rates but as soon as the oil near the fractured area is recovered the production declines rapidly. As a result, recovery from these unconventional shale oil reservoirs with hydraulic fracturing is about 6-10% of oil in place.

There is very little work done in the area of improving oil recovery from unconventional reservoirs. Usually, these reservoirs are enormous in size and hold billions of barrels of oil in place and even small improvements in recovery yield significant amounts of oil. This thesis addresses a production technique, which improves the oil recovery in tight reservoirs by introducing shut-in cycles.

Shut-ins have been viewed negatively since oil and gas were first discovered because they are viewed as a hindrance to both production and cash flow. One of the objectives of this thesis is to change that perception by proposing a method of executing systematic shut-in cycles to enhance/improve the ultimate recovery. It is well known that shutting-in a well allows the wellbore to come back to equilibrium with reservoir pressure, allowing the flow rate to increase. However, this increase is believed to be short-lived and the long-term effects have not been studied in detail. This thesis seeks to evaluate that as well.

An innovative way of utilizing shut-in cycles in an oil-field is proposed in this thesis. This method enables continuous production along with the added benefits from shut-in cycles. The objective of this research and method is presented below.

1.1. OBJECTIVES OF RESEARCH

The objective of this thesis is to investigate the impact of repeated shut-in/production cycles on hydrocarbon recovery in low-permeability reservoirs. The primary focus of this study can be conveyed by the following objectives:

(1) Develop a model which can simulate a range of low permeability reservoirs and emulate production practices followed by the industry in unconventional resources.

(2) Design a pattern for shut-in/production cycles with varying shut-in/production periods to test the concept.

(3) Compare the Estimated Ultimate Recovery (EUR) for all the cases and identify the optimum shut-in cycle schedule.

(4) Propose a way of introducing this technique to the industry.

The results of this work are expected to improve reservoir management in unconventional reservoirs by providing production practices that result in better long-term recovery. The work is also expected to lead to a better understanding of production mechanisms, drainage areas, and overall performance of multiple fractured horizontal wells (MFHW) in low-permeability reservoirs when subjected to multiple shut-in cycles.

1.2. METHOD OF STUDY

This research uses numerical methods to model production from a multi-stage hydraulically fractured horizontal well in a low-permeability reservoir. CMG software is used to build the model. CMG-IMEX, a three-phase, black-oil reservoir simulator is used for the simulations.

In order to study the reservoir behavior when subjected to shut-in/production cycles, several cases were built and they are explained in Section 3.3 in detail. Figure 1.1 illustrates the model, location of the well, and fractures placed in the reservoir.

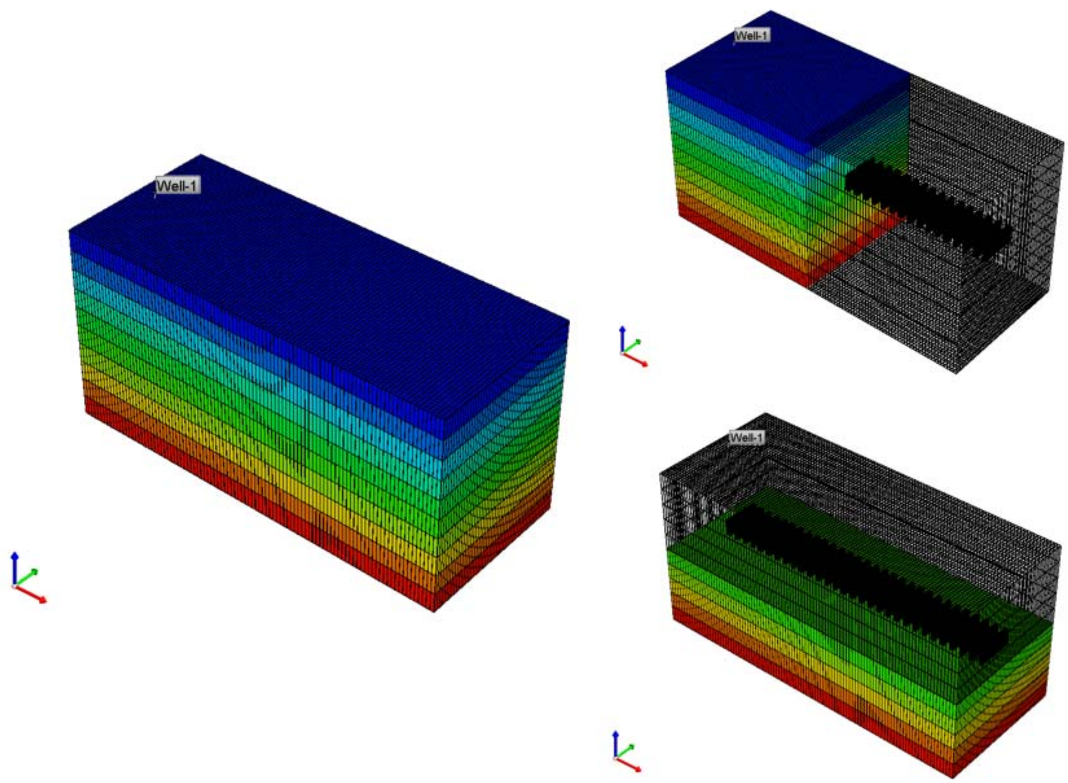


Figure 1.1. Model with one well.

First, a horizontal well with 30 transverse fractures is placed in the center of the model. Next, the well is simulated with various shut-in/production periods while varying the permeability from 0.000001 to 10 md in the model. The duration of the simulations is 50 years (assumed productive life) and the ultimate recovery is compared with the normal constant bottom-hole pressure case to analyze the impact of the shut-in/production cycles.

In order to evaluate this technique in an industry-accepted form, a model with two multi-fractured horizontal wells is simulated with an optimum shut-in period, changing the pattern in which both wells operate relative to each other to analyze the interference effect of shut-in cycles and how that affects the recovery. Since shutting-in all the wells at once can be a tough decision for the operators due to the impact on cash flow, this extension of the study enables a way to shut-in the desired number of wells at once; keeping the rest flowing, followed by cycling this process. Such methods can be readily accepted in the industry as using them never halts the production completely while still improving the ultimate recovery. Figure 1.2 illustrates the second model for this study.

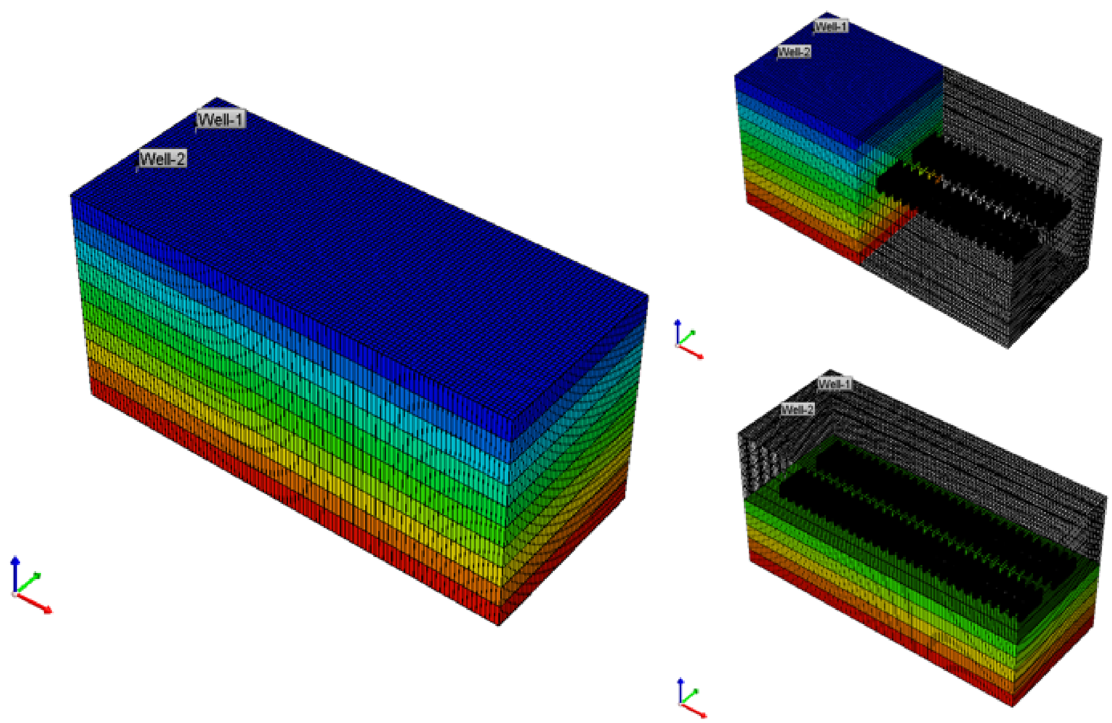


Figure 1.2. Model with two wells.

2. LITERATURE REVIEW

2.1. MULTIPLE FRACTURED HORIZONTAL WELL

In this technique, the horizontal well is stimulated by creating numerous hydraulic fractures along the wellbore. This method improves production significantly, as it expands the contact area of the wellbore with the reservoir. Also, fracturing along the wellbore improves the flow by providing a higher conductive path for the fluids and can extend the natural fracture network. Currently, it is the most efficient way of producing from low-permeability reservoirs and is the most common horizontal well completion and stimulation practice. Figure 2.1 illustrates a typical schematic of the fractured horizontal well.

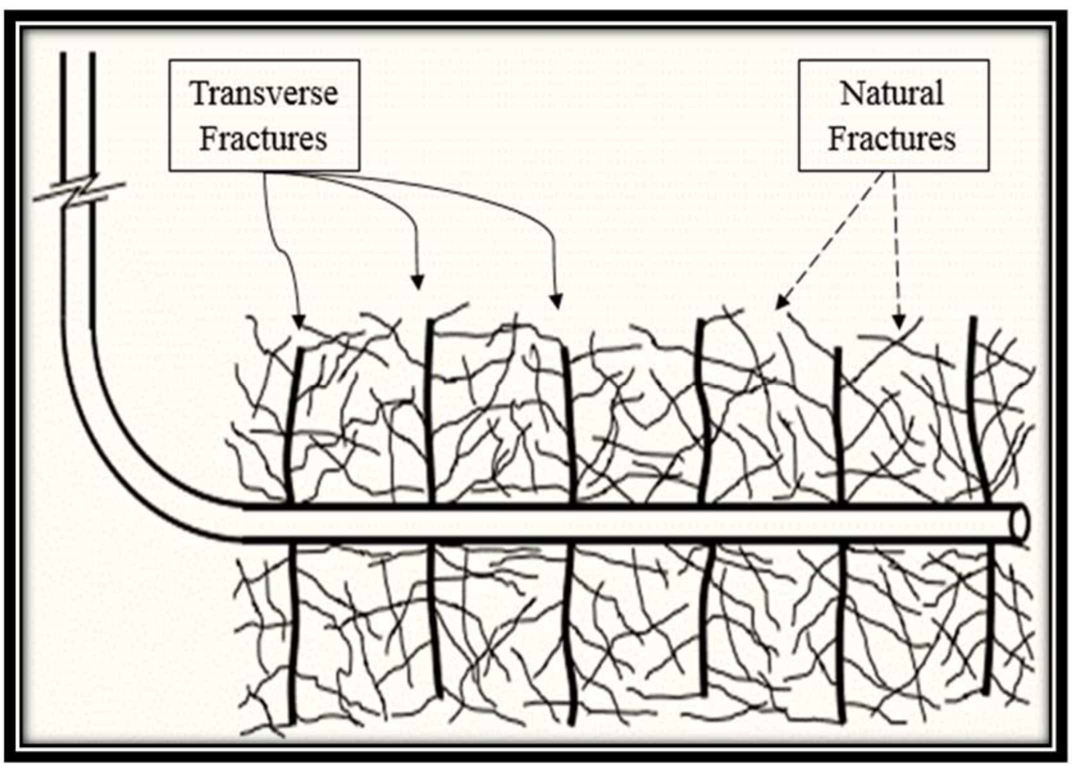


Figure 2.1. Schematic of the fractured horizontal well (Torcuk et al., 2013).

Recovery from such wells strongly depends on the fracture orientation. Optimally designed transverse or longitudinal fractures facilitate rapid depletion of the reservoir and impacts the recovery in low-permeability reservoirs. A horizontal wellbore is most stable when drilled in the direction of minimum stress (Soliman, 2000). A misaligned wellbore can result in a disoriented fracture as it leaves the wellbore. Once beyond the sphere of influence of the wellbore the fracture reorients itself into a direction perpendicular to minimum stress. Such a situation can lead to high pressures due to the effects of misalignment or tortuosity. As a result, designing such a completion properly is crucial.

Considering the popularity and effectiveness of this completion architecture in the industry, a similar model was built for this simulation study. The model used included 30 transverse fractures in a horizontal well. Transverse fractures perform better than longitudinal when the permeability is less than 0.3 md and longitudinal perform better when the permeability is greater than 2 md, between 0.3 and 2 md further comparisons are needed on the basis of number of transverse fractures to be placed (Kassim et al., 2016).

2.2. FLOW REGIMES IN MULTIPLE FRACTURED HORIZONTAL WELLS

Identifying flow regimes is an important process in production analysis and interpreting these regimes helps to develop accurate reservoir property estimates and long-term production forecasts. This section explains the major flow regimes observed in MFHW. Some of these flow regimes are identified in the model used for this study and are shown in the latter part of this section.

Horizontal wells with multiple fractures exhibit a unique flow regime; transient flow periods are elongated, and most wells reach their economic cut-off rates either during transient flow or shortly after reaching the boundary dominated flow period. Table 2.1 lists the flow regimes in multiple fractured horizontal wells (MFHW).

Table 2.1. Flow Regimes in multiple fractured horizontal wells (Fekete.com).

Early Time	**Middle Time**	**Late Time**
• Wellbore storage • Vertical Radial Flow within the fracture • Linear Flow within the fracture • Bilinear Flow	• Early Linear Flow • Early Radial Flow • Compound Linear Flow • Late Radial Flow	• Pseudo-Steady State Flow

During the early time before the well is stimulated with fractures, a vertical radial flow is developed in the vertical plane as shown in Figure 2.2. Once the horizontal wellbore intersects one or more fractures, fluid flows through the fractures into the wellbore. Usually, this flow regime is masked by wellbore storage and is not observed.

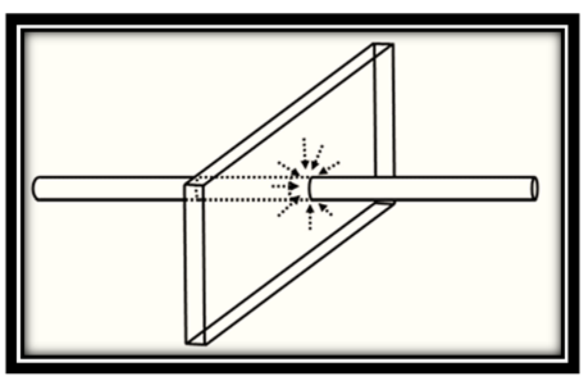


Figure. 2.2 Vertical Radial flow in fracture (Source: Fekete).

Linear flow into the fractures is followed by vertical radial flow; this happens for bi-wing fractures with half-length significantly greater than their height. This region is also generally masked by wellbore storage. Figure 2.3 illustrates this phenomenon.

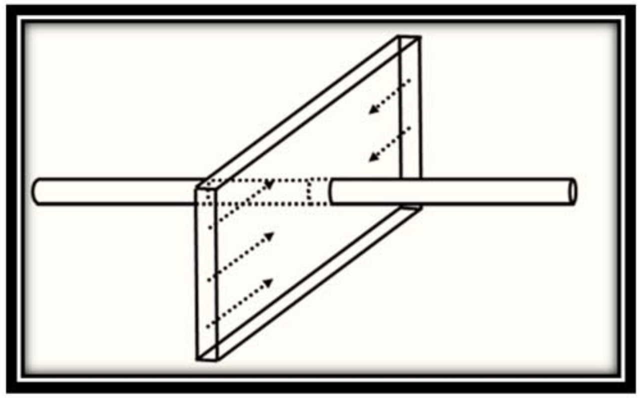


Figure 2.3. Linear flow within fractures (Source: Fekete)

Bilinear flow marks the end of the early time region and occurs when two linear flow periods exist at the same time. One linear flow region occurs within the fracture towards the well and the other occurs in the formation towards the fracture. Figure 2.4 illustrates this flow.

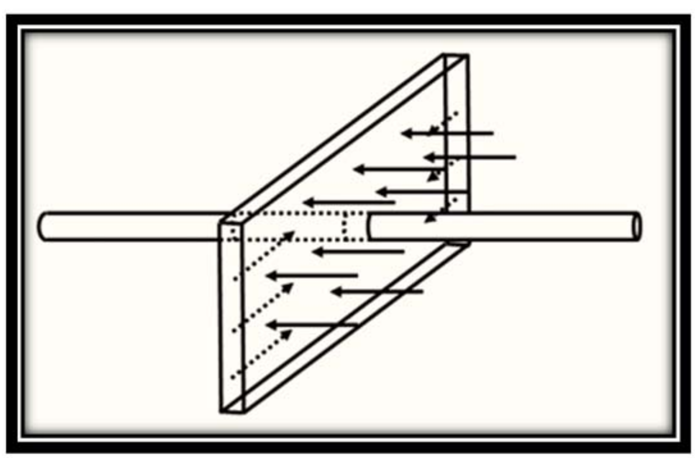


Figure 2.4. Bilinear flow in multi-frac horizontal well (Source: Fekete).

Next, comes the middle time or the transient time, the first flow regime in this period is the linear flow towards the fractures of the multi-frac horizontal well as shown in Figure 2.5. The transients within the fractures are also stabilized at this time.

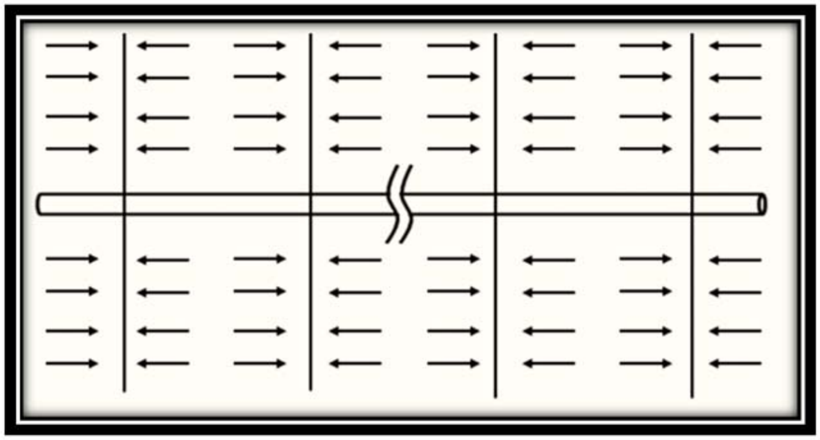


Figure 2.5. Linear flow towards fracture in multi-frac horizontal well (Source: Fekete).

After the end of the linear flow and prior to the fractures starting to interfere with each other, an early radial flow regime as illustrated by Figure 2.6 is observed. This is usually observed in fractures that are apart from each other and is unlikely to be seen in present unconventional wells due to the close fracture spacing.

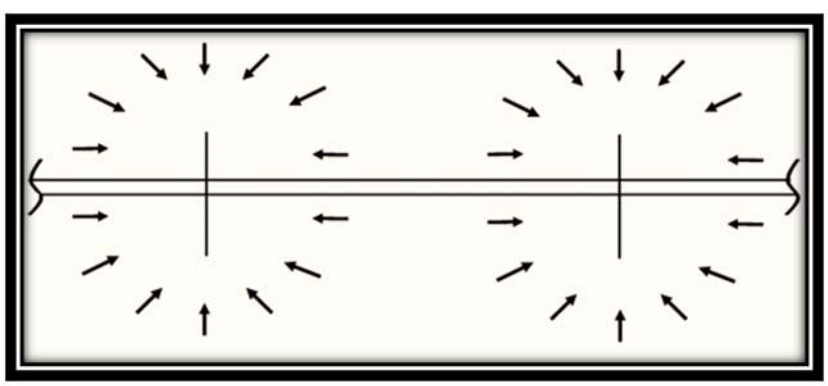


Figure 2.6 Early radial flow in MFHW (Source: Fekete).

Once the fractures have interfered, compound linear flow may be observed. Compound linear flow is defined by the flow from the outer zone towards the stimulated reservoir volume (SRV) and is shown in Figure 2.7.

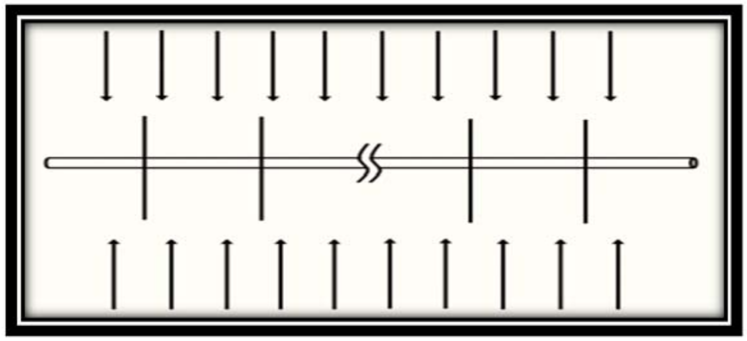


Figure 2.7. Compound Linear Flow (Source: Fekete).

Characterized by zero slope plot on the log-log derivative plot is the Late Radial flow which is seen after compound linear flow. This flow is unlikely to be observed in practice as it occurs only when the well exists all alone in an under developed field for a long time. Figure 2.8 depicts this flow.

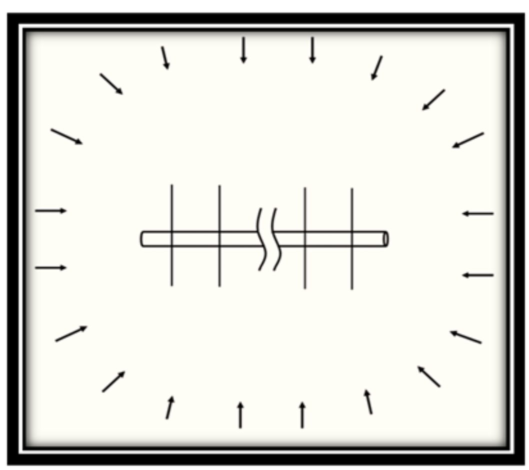


Figure 2.8. Late Radial Flow (Source: Fekete).

Following late radial flow begins the late time region, this region begins when the radius of investigation has reached all the boundaries, stabilized flow is reached and the reservoir exhibits Pseudo-Steady state or steady state flow. These boundaries are no-flow boundaries and the pressure throughout the reservoir decreases at the same constant rate.

Table 2.2 shows the flow regime that could be identified using the model created for this study.

Table 2.2. Flow regime in the reservoir model for this study.

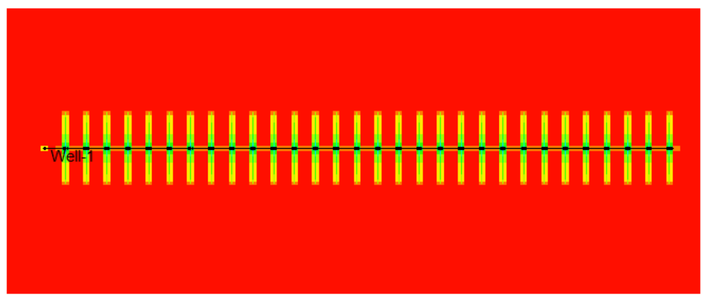
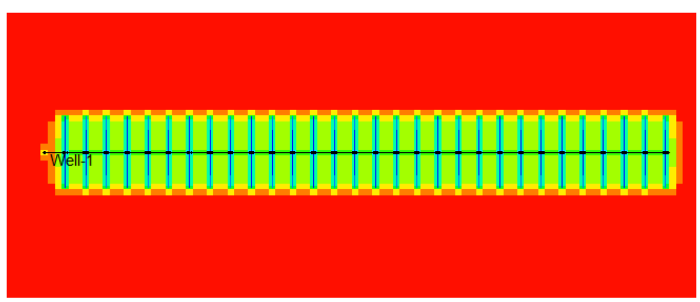
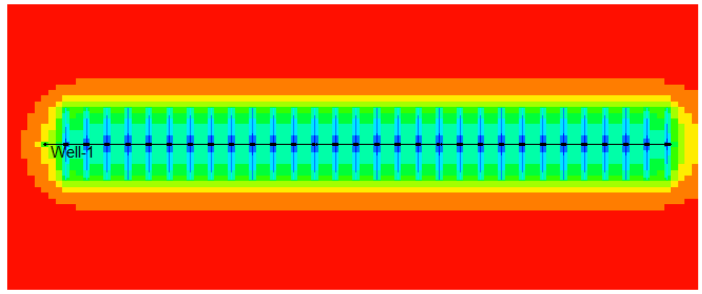
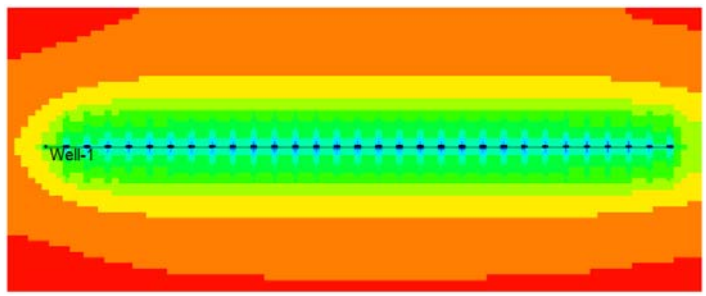
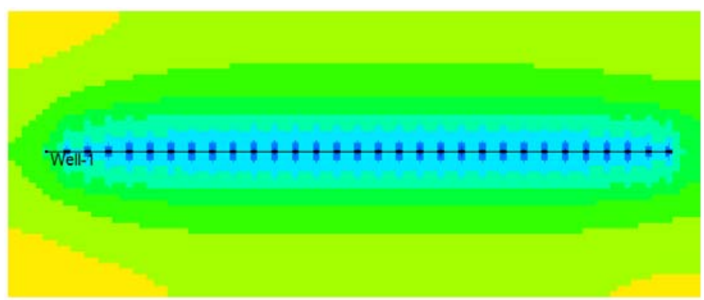
Flow Regimes	Model
Bilinear/Linear Flow: Fluid flows down the fracture, flow across tips is negligible, and fracture behaves independently of the other fracture	
Pseudo Pseudosteady State Flow: Pressure interference between fractures dominate, it is an approximate pseudo steady state flow, which depletes the inner stimulated reservoir volume (SRV) and has a limited contribution from outer SRV.	

Table 2.2. Flow regime in the reservoir model for this study (cont.).

Compound Linear Flow: Fracture interacts, the flow pattern is predominantly normal to the vertical plane that contains the horizontal well.	
Pseudo radial/ Elliptical Flow: Flow across the tips of the HW is dominant, flow resembles long-term behavior of vertically fractured wells.	
Boundary Dominated Flow: Flow occurs when boundaries are reached; as the boundaries are closed flow eventually reaches Pseudo-steady state.	

2.3. PREVIOUS RESEARCH

This section is intended to present both, an overview of previous research in the area of cyclic shut-in and similar production techniques and general trends in low permeability reservoir development. Although the research published in this field is very limited, few relevant studies are cited in this Section.

The term ‘cyclic’ has been used in the industry since 1960’s for work which was mainly devoted for water injection as a method to improve oil recovery with optimizing the injection. One such study was conducted by Raza in 1971; he found that additional oil from extensively fractured reservoirs could be recovered with cyclic water pulsing. This method involved alternating pressurizing and depressurizing of the reservoir. During the pressurizing phase, the injected water was forced under high-pressure from the fracture network into the low permeability (matrix) and during the depressurizing phase, the fluids were produced out of the matrix into the fracture network, which could then help the hydrocarbon flow towards the producing wells. This method was among the first effective methods involving cyclic processes; although the additional recovery by this method could only be seen if the initial oil saturation was more than the critical value.

In 2003, a similar study was carried out by Arenas et al. The goal was to optimize water flooding in tight fractured formations, and was done by cycling selected intervals of the well rather than the entire well in a horizontal injection well. By controlling the water injection across these intervals, it was possible to prevent water breakthrough between producer-injector pairs due to the fractures, thereby, improving the water flood.. This technique resulted in reduction of cumulative water with no impact on oil production.

Al-Mutairi et al. in 2008 also used a similar technique to handle excessive water production in mature oil fields and referred to it as a Cyclic Production Scheme (CPS). Wells with high water cuts were subjected to alternating shut-in and flowing periods; with a uniform duration through the shut-in and flowing period. Three different setups involving 6-months, 12-months, and 24 months duration were simulated. The cyclic production scheme resulted in a significant reduction in water production but had no impact on oil production. Figure 2.9 and 2.10 show the results obtained from this simulation study.

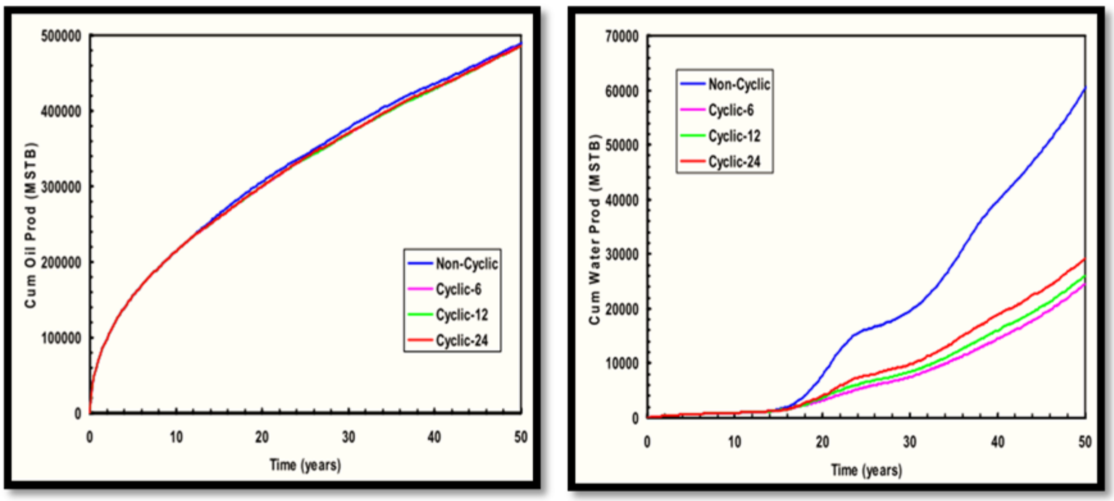


Figure 2.9. Cumulative oil production (left) and Cumulative water production (right) vs. Time.

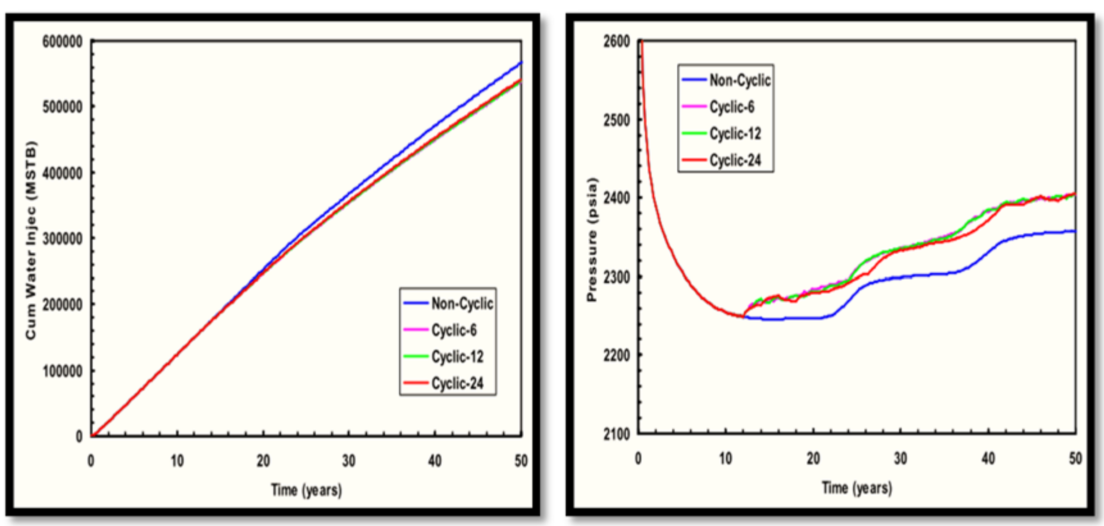


Figure 2.10. Cumulative water injection (left) and Average reservoir pressure (right) vs. Time.

It was concluded that use of CPS leads to better production performance by reducing the water production.

Al-Zahrani (2013) published a case study on performance of Cyclic Production Scheme (CPS) on 93 wells mostly with 80% or higher water cut. Problems associated with water production such as water coning and water channeling were also addressed in this study. It was found that CPS greatly reduced the water production and also affected the oil production slightly. The reason behind this was the mechanism of fluid movement; it was different in cyclic production mode; during the shut-in period, gravity segregation restored the oil column in the wellbore region and thus the water coning was reduced.

In 2012, Whitson et al. presented a method to eliminate production loss due to liquid loading in tight gas wells. He compared three scenarios, (1) an ideal situation, where all of the liquids entering the reservoir of condensing in the tubing are continuously removed without shut-ins, (2) typical of most wells today, a meta-stable liquid-loading condition with low gas rate, and (3) by proposed strategy of cyclic shut-in. Figure 2.11 shows the gas well performance before & after the onset of liquid loading.

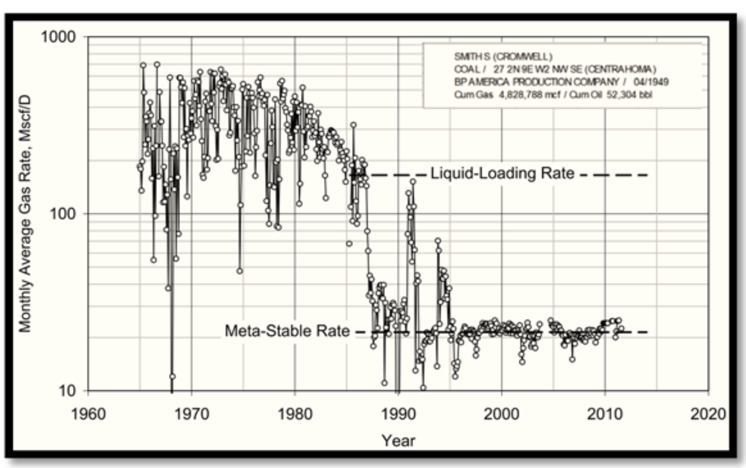


Figure 2.11. Gas well performance before and after liquid loading.

The method of cyclic shut-in control was applied automatically as soon as the liquid loading rate was reached. The shut-in period was very short (~hour), in this time the gas continued to flow into the wellbore and near-wellbore region with some pressure increase. High transient gas rates were observed on reopening. Also, after each shut-in period, the subsequent production period shortened when compared to the previous period and this process continued until the well could no longer produce at an economical rate. In this simulation study, the cyclic shut-in control was shown to be effective in recovering the same amount of gas that would be recovered in a hypothetical ideal well situation (continuously unloaded without shut-ins) and shorter shut-in times were more effective. Such cyclic shut-in periods is a good way to identify liquid loading problems in wells and to determine wells requiring deliquification and artificial lift.

On the contrary, there is published research against the practice of shutting the wells for improved performance. This was an encouragement for this research as there was an opportunity to start this work from the beginning in low-permeability environments. The relevant studies are presented in the next paragraphs and then overall conclusion from the literature review is discussed in Section 2.3.

In 2013, Crafton et al. presented work that showed that delaying the first production after fracture stimulation of multi-frac horizontal well completions is detrimental to recovery. The study concluded that shut-ins are generally not harmful, however, they do not yield enough benefit to use as a business practice and that shut-in related damage accrues over time during subsequent shut-ins. Also, the duration of shut-in had no direct correlation with the severity of damage arising from it and longer production periods are beneficial to the reservoir-wellbore connectivity.

Similar conclusions were drawn from two other studies; that were conducted in Colorado school of Mines by Fakcharoenphol et al. (2013) and West Virginia University by Cheng (2012). After a month-long shut-in followed by a multi-stage fracture stimulation in a horizontal well, a significant increase in flow rates of oil and gas was seen. It was also seen that water rate was reduced. The ultimate recovery of oil and gas was also analyzed and found that increase in oil and gas rate was a temporary effect and had no impact on the overall recovery. The cumulative gas stayed the same and the reason behind this anomaly was found out to be the mass transfer of filtrate into the matrix by gravity, capillary and/or osmotic mass transfer during the shut-in period.

One such field example is from a Marcellus gas well, Figure 2.12 shows the increase in the gas flow rate after a shut-in of 6 months.

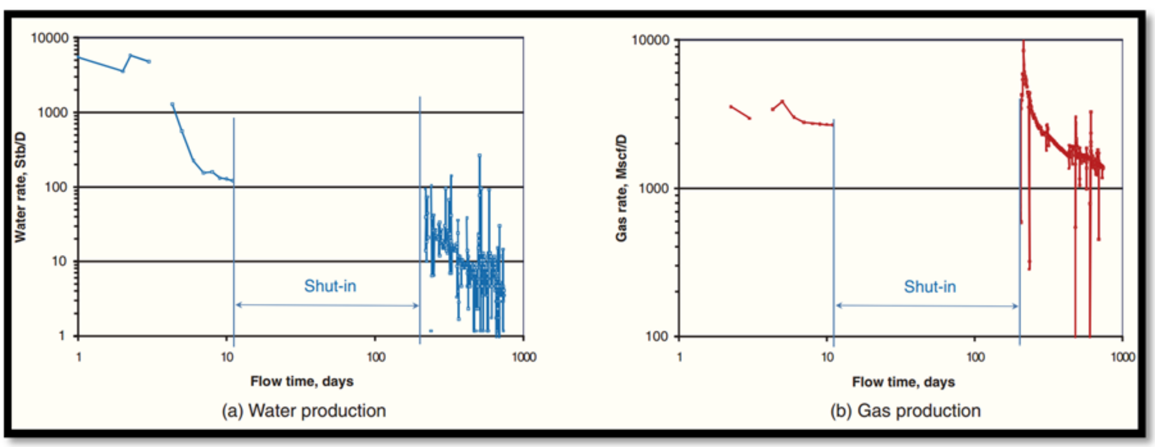


Figure 2.12. Field production data from a well in Marcellus Shale, Water rate (STB/D) vs. Time (Days) on the left and Gas Rate (Mscf\d) vs. Time (Days) on the right. (Source: Cheng 2012).

Shut-in periods helped in reducing the liquid saturation in the natural fractures and allowed the gas to flow at higher rates from the fractures, this effect was temporary and depended on the nature of pore connectivity.

Kandlakunta et al. carried a similar simulation study in 2016 in low-permeability reservoirs, it involved a single phase gas numerical model which was subjected to repeated shut-in/production cycles to study the impact of shut-ins on the ultimate recovery of gas. The permeability range of the study was from 0.0001 md to 1 md (study included analysis of 0.0001 md, 0.0005 md, 0.001 md, 0.01 md, 0.1 md and 1 md reservoirs). The well was kept on cyclic production for the first 20 years followed by normal flow at constant bottom-hole pressure for the next 30 years. It was concluded from this study that ultimate recovery can be improved by cyclic production by almost 3% in the most optimum case.

2.3.1. Conclusion. It can be concluded that shut-in cycles do impact the flow rates of oil and gas temporarily, by increasing them three to four folds when compared with the flow rate before shut-in. However, this effect is temporary and may not affect long-term production and ultimate recovery. It is also observed that in almost all the studies, water production was reduced significantly.

Secondly, shut-in cycles allow the gravity segregation of the water from the fractures which clears the obstructed fracture network and promotes hydrocarbon flow. Other reasons include saving the reservoir energy by maintaining the pressure, which brings the wellbore pressure closer to the reservoir pressure and this promotes the flow rate.

Shut-ins also help in gas wells with liquid loading problems. The ultimate recovery of gas in such cases can be compared with similar wells having no water production throughout its life. Also, there is no literature that suggests improvement in the ultimate recovery of oil and gas because of shut-ins other than anecdotal data from the Cotton Valley Formation which indicates that the wells with the best recovery were wells that were curtailed in the 1980's.

2.3.2. Implementation. This research was conducted keeping in mind the benefits and drawbacks of shutting the well. The idea was to have free gas in the reservoir (saturated reservoir). Having free gas could help in pressure build-up during the shut-in period and could promote the flow of oil in the fracture network after gravity segregation of water.

3. RESERVOIR SIMULATION

This section explains about the reservoir model, the properties of the fluid and the rock fluid properties used. Latter part discusses the shut-in/production cycle pattern and implementation. CMG-IMEX simulator is used for this work.

3.1. RESERVOIR MODEL

Two reservoir models were built for this study, the first model consisted of one well in the center layer and was primarily used for this study. The second model included two wells and was developed to emulate field conditions in simulating the repeated cyclic shut-in technique for managing production from multiple wells.

3.1.1. Model with One Well. A 3-D Multi-phase numerical model was used for this research and was built using CMG-Builder. This model contains a horizontal well with 30 transverse fractures in a rectangular reservoir. The horizontal well is placed in the center of the reservoir and all the fractures are identical and spaced uniformly along the wellbore. Table 3.1 lists the dimensions of the model followed by Figure 3.1 and Figure 3.2 which shows the schematic of the model.

Table 3.1. Dimension of the simulation model.

Parameter	Value	Parameter	Value
Grid Blocks, I-Direction	100	Block Width, I-direction	100*97
Grid Blocks, J-Direction	50	Block Width, J-direction	50*80
Grid Blocks, K-Direction	10	Block Width, K-direction	10*40

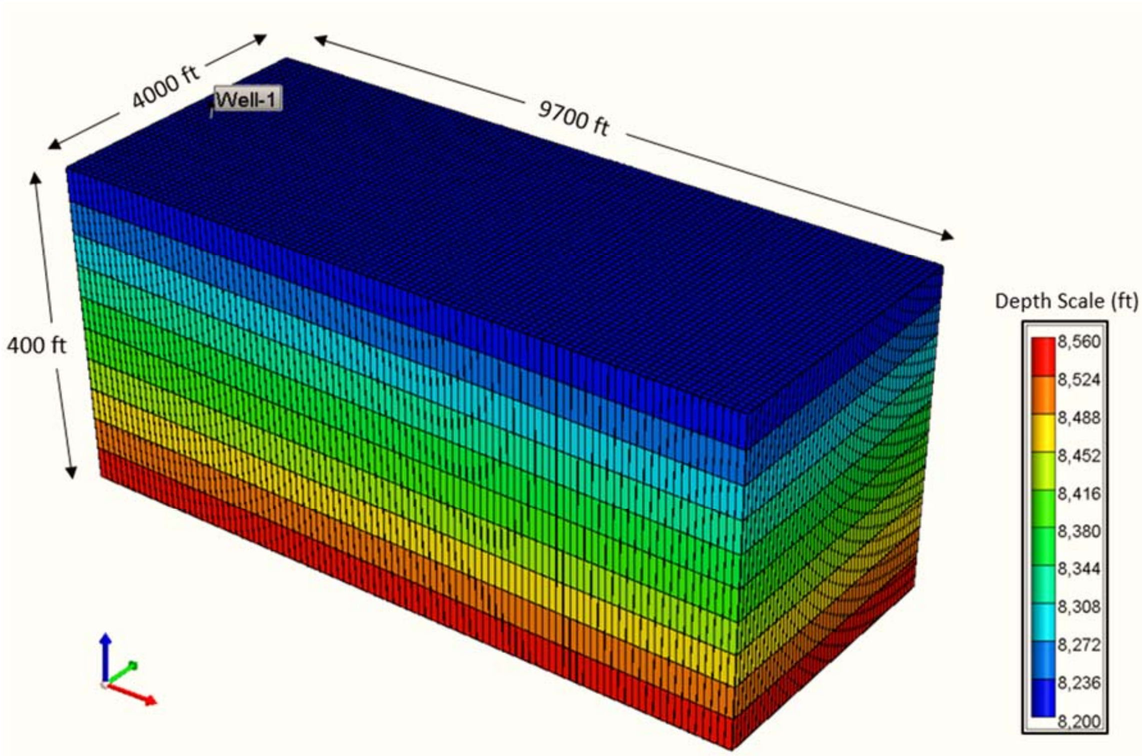


Figure 3.1. Schematic of the model with single well.

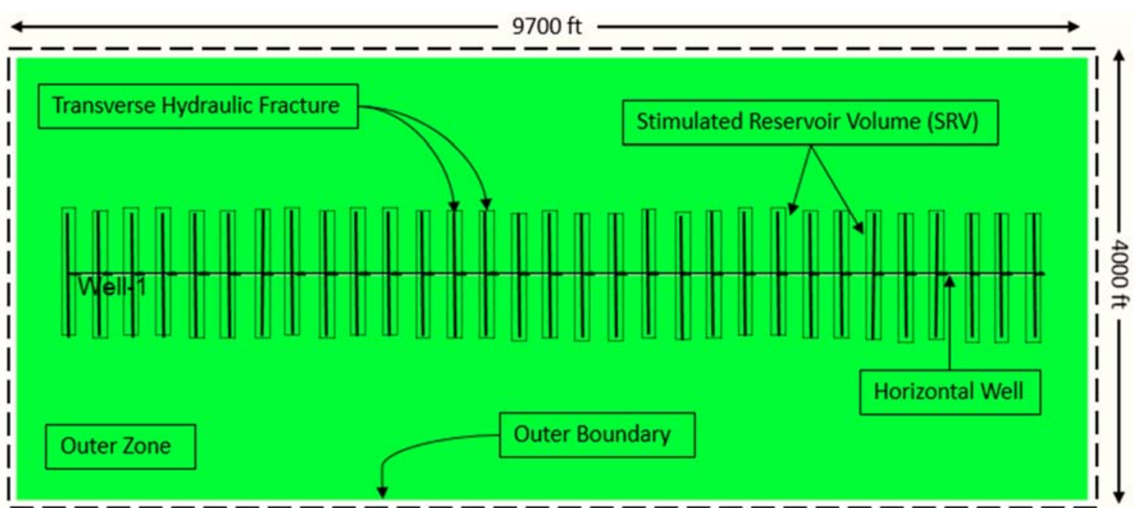


Figure 3.2. Multi-Frac horizontal well in the center (Top View) of the model.

The well architecture resembles a single multiple fractured horizontal well in the Wolfcamp Formation, which is one of the tight oil formations in the Permian Basin. The reservoir properties are changed for this study as it involves analyzing the reservoir performance to shut-in/production cycles over a range of permeabilities. Also, the outer boundaries are closed and do not allow any flow inside. Table 3.2 lists the well and reservoir parameters followed by the fracture properties in the next table.

Table 3.2. Well and Reservoir parameters.

Parameter	**Value**
Reservoir Pressure, P_R	3500 psi
Porosity, Φ	10 %
Skin, S	0
Outer-Zone Permeability, K	0.000001 to 10 md
Permeability Anisotropy, K_v/K_h	0.1
Grid Top Depth	8200 ft
Grid Bottom Depth	8600 ft
Pay Zone	400 ft
True Vertical Depth (TVD) of Well	8400 ft
Reservoir Temperature, T_R	200 °F
Number of Fractures, n_f	30
Horizontal well length	8827 ft
Formation Compressibility, C_f	3E-06 1/psi

To model the fractures, a denser grid was used as compared to the grid used for the reservoir. This provided more detailed information about the fracture and near fracture region. When stimulating shale reservoirs a complex network of natural fissures and fractures may be created and dilated. This volume is called the Stimulated Reservoir Volume (SRV) and is marked with a dotted rectangular region near the fracture in Figure 3.2; it can also be seen in Figure 3.3, which illustrates the refined grid used for the transverse fractures. Fracture parameters and grid dimensions are listed in Table 3.3. Also, the model used for this study is a single-porosity model and does not account for natural fissures which the industry most commonly assumes when referred to SRV. This volume can be calculated by using the Equation 1.

$$\mathbf{SRV} = \mathbf{2} * \mathbf{X}_{\boldsymbol{f}} * \mathbf{H}_{\boldsymbol{f}} * \text{ Lateral Length} \qquad (1)$$

Where,

- $\mathbf{X}_f$ = Fracture Half-Length
- $\mathbf{H}_f$ = Fracture Height

Table 3.3. Fracture parameters used for simulation model with one well.

Parameter	Value
Fracture Width	0.001 ft
Fracture Permeability	50 md
Fracture Half-length	500 ft
Number of refinement in I-Direction	5

Table 3.3. Fracture parameters used for simulation model with one well (cont.).

Number of refinement in J-Direction	5
Number of refinement in K-Direction	1
Grid Cell width	2 ft

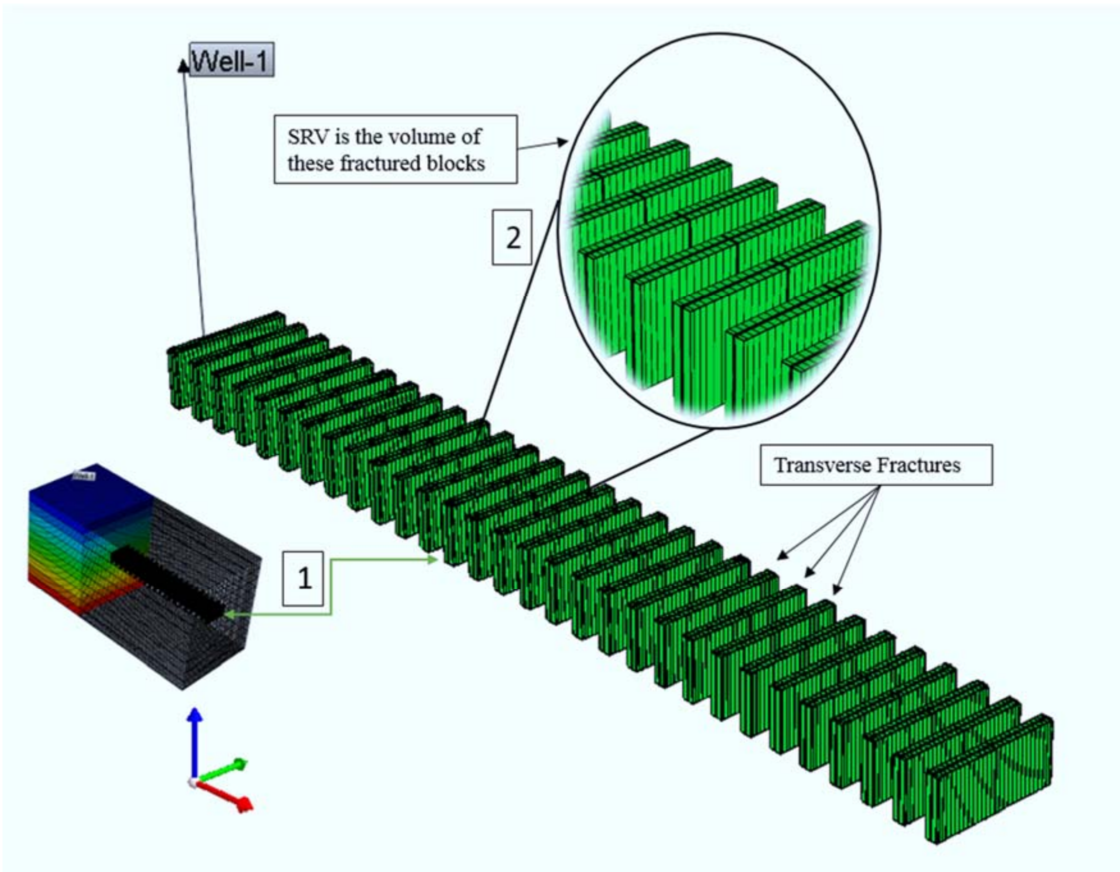


Figure 3.3. Zoomed section of (1) Transverse fractures from Single Well Model & (2) Fracture Grid.

3.1.1.1 Fluid properties. In order to emulate the Wolfcamp Formation a black-oil model was used with Wolfcamp fluid properties. In the black-oil model, components with similar chemical properties are treated as a single entity. The reservoir fluids other than water are assumed to consist of only two pseudo-components, a gas component, and an oil component. Table 3.4 and 3.5 lists the fluid properties.

Table 3.4. Oil, Gas, and Water Densities.

Parameter	**Value**	**Parameter**	**Value**
Oil density	44 °API	Gas gravity (Air = 1)	0.650
Water density	60.8 lb/ft3	Reservoir Temperature	200 F

Table 3.5. PVT Table.

P (psi)	**Rs (ft3/bbl)**	**Bo**	**Bg (bbl/ft3)**	**Oil Viscosity (cp)**	**Gas Viscosity (cp)**
14.696	4.73034	1.0682	0.225046	0.908791	0.013324
280.383	54.5774	1.0881	0.011529	0.748515	0.013539
811.757	183.614	1.1421	0.003819	0.55307	0.014275
1077.44	255.929	1.1738	0.002826	0.493772	0.014759
1608.82	411.042	1.2447	0.001842	0.412056	0.015938
2140.19	577.017	1.3242	0.001367	0.357886	0.017357
2671.57	751.628	1.4112	0.001098	0.31895	0.018948
2937.25	841.714	1.4572	0.001005	0.303234	0.019782
3202.94	933.472	1.5049	0.000931	0.289383	0.020629
3734.31	1121.58	1.6050	0.000819	0.266025	0.022333
4000	1217.74	1.6572	0.000777	0.256063	0.023179

3.1.1.2 Rock-fluid properties. The reservoir rock is considered water-wet, and the relative permeability curves are illustrated in Figure 3.4 and Figure 3.5. A generalized-Corey relation form is used for 2 phase model and Stone-2 for the 3-phase correlation.

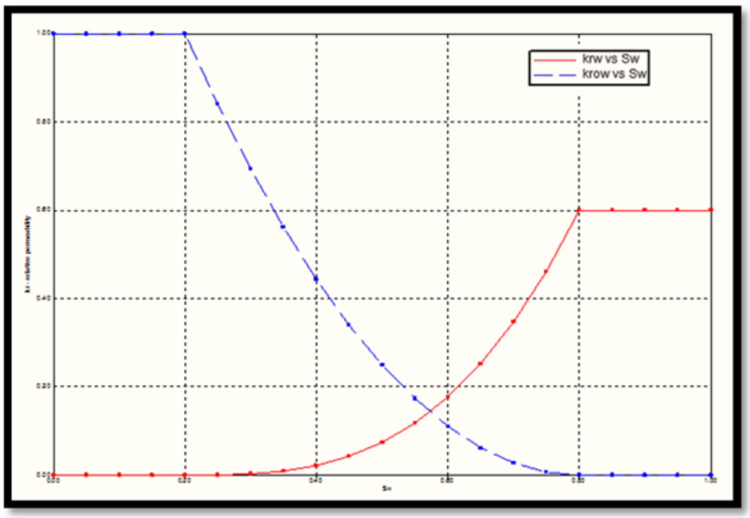


Figure 3.4. Water-Oil Table with K_r on y-axis and S_w on the x-axis.

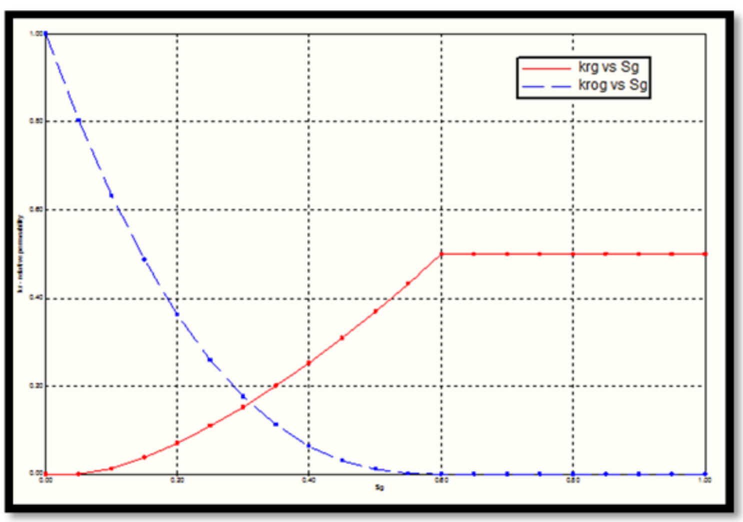


Figure 3.5. Gas-Oil Table with K_r on y-axis and S_g on the x-axis.

3.1.2. Model with Two Wells. This model resembles the first model in dimension and fluid properties, but has two wells in the center of the drainage area. These wells are identical and are placed 1600 ft apart, the purpose behind this model is to study how shut-in/production cycles can be applied in a real field situation with multiple wells. Section 3.3.2 explains the procedure followed by the conclusion in Section 5.1.

Figure 3.6 and 3.7 illustrate the model and the well placement in the center of the model.

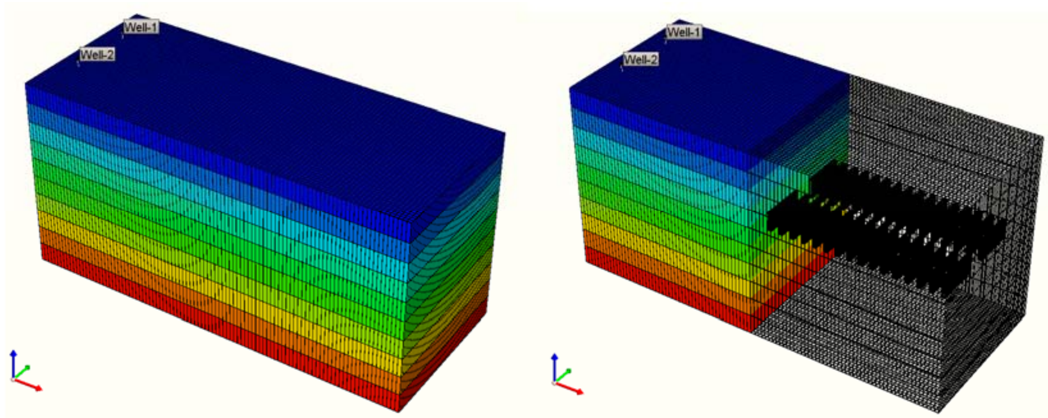


Figure 3.6. Model with two wells.

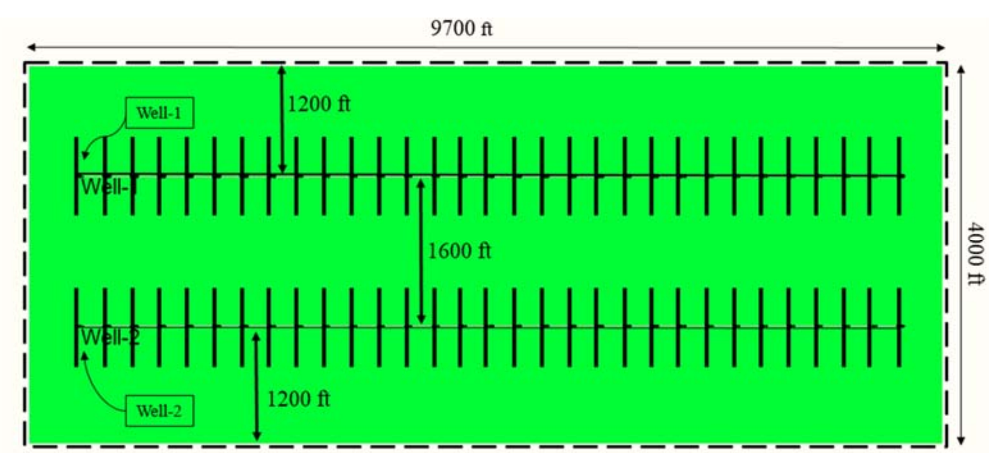


Figure 3.7. Two wells in the center (Top View) of the model.

3.2. SHUT-IN/PRODUCTION CYCLES

In this study, the well performance was simulated for 50 years, which was assumed to represent the productive well life. Four different shut-in periods of 2 Weeks, 1 Month, 6 Months and 1 Year were applied in a specific pattern, and the production in each case was compared with a normally producing well. This technique of production with alternating flowing and shut-in periods is referred to as Repeated Cyclic Production Scheme (RCPS).

The well is subjected to shut-in/production cycles in the first five years followed by the next five years of normal flow at a constant bottom-hole pressure of 250 psi; this procedure is repeated until the end of 50 years. Figure 3.8 shows the first ten years of production when shut-in/production cycles are applied.

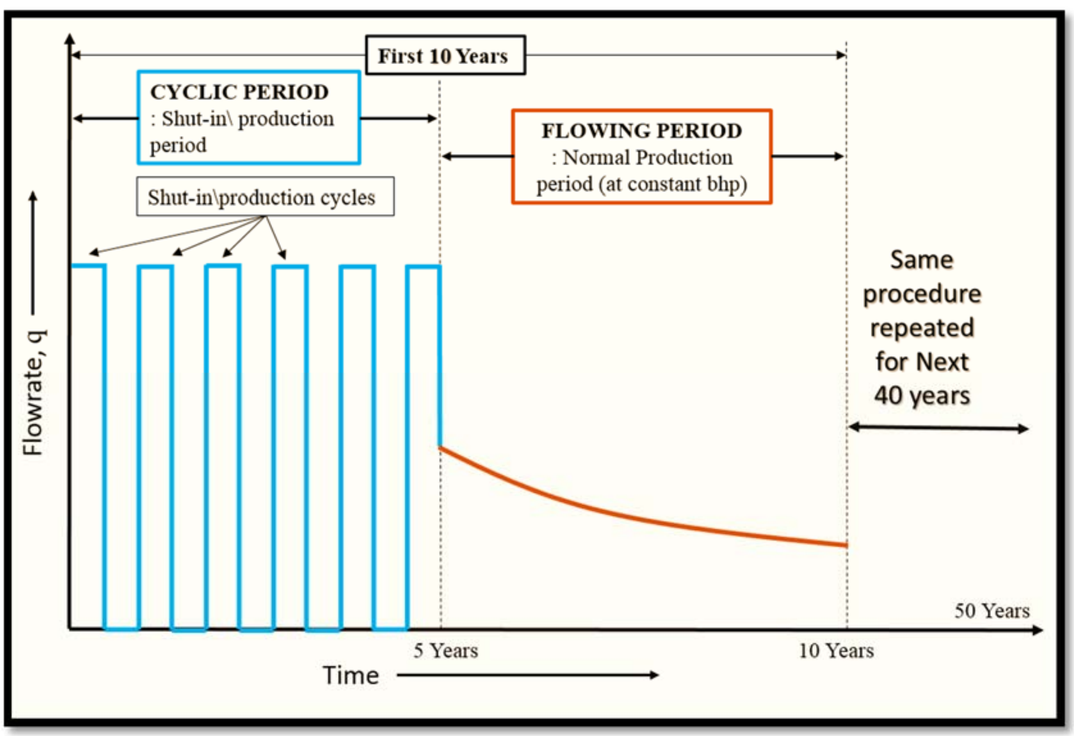


Figure 3.8. Repeated cyclic production scheme pattern.

Figure 3.9 illustrates the flow rate vs. time graph with real simulation data when the well is producing with RCPS technique for 50 years. The figure shows the production data from two cases; the orange line indicates the flowrate of oil in a normal-constant bottom-hole pressure of 250 psi scenario and the blue line shows the oil flowrate with RCPS of 1-year.

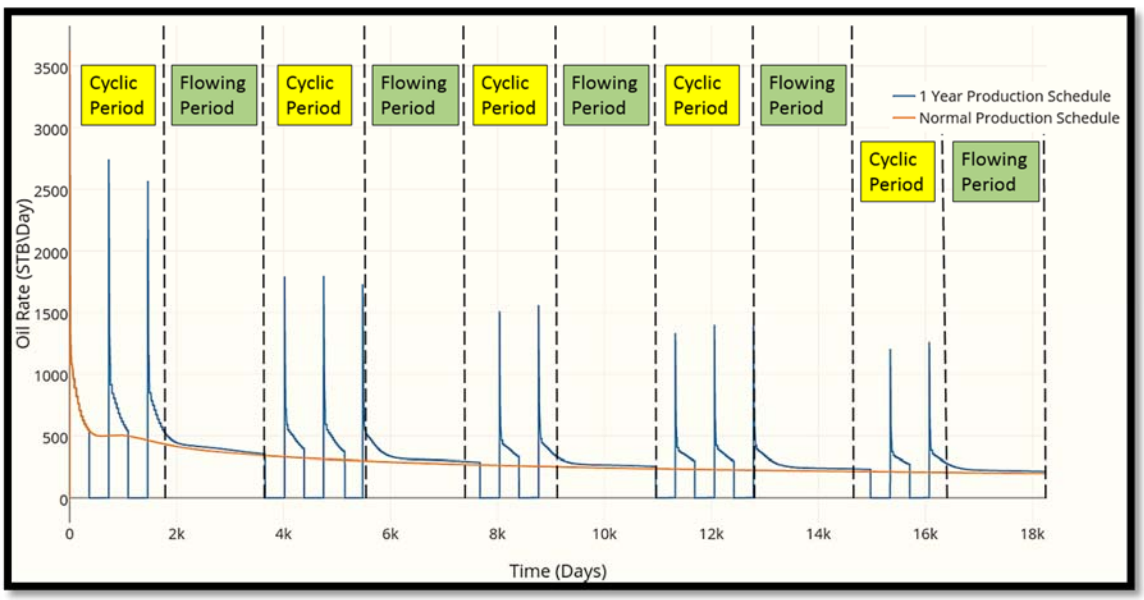


Figure 3.9. Oil Flow rate vs. Time for 1-year schedule vs. Normal production.

In the same way, an RCPS of 2-weeks would signify a shut-in/production cycle of a 2-week duration and a similar process is followed for 1-month and 6-months shut-in/production cycle. Also, the period when the well is on shut-in/production cycles is referred as Cyclic Period (CP) and the normal production period is called Flowing Period (FP); the same can also be seen from Figure 3.9 and 3.10.

Going back to the case explained in Figure 3.9, the shut-in/production cycles of 1 year can be seen in the figure during the cyclic periods, it can also be seen that flowrate increases three to four folds after shut-in when compared to the normal production. Also, if observed closely, the flow rate for the same well with 1 Year-RCPS is slightly more than Normal Production Schedule during the Flowing Period; the reason for this slight improvement is because of the shut-in\production cycles which are being applied during the cyclic period.

For the same scenario, the cumulative oil production is shown in Figure 3.10 with a brief description of how it impacts the ultimate recovery in the next paragraph.

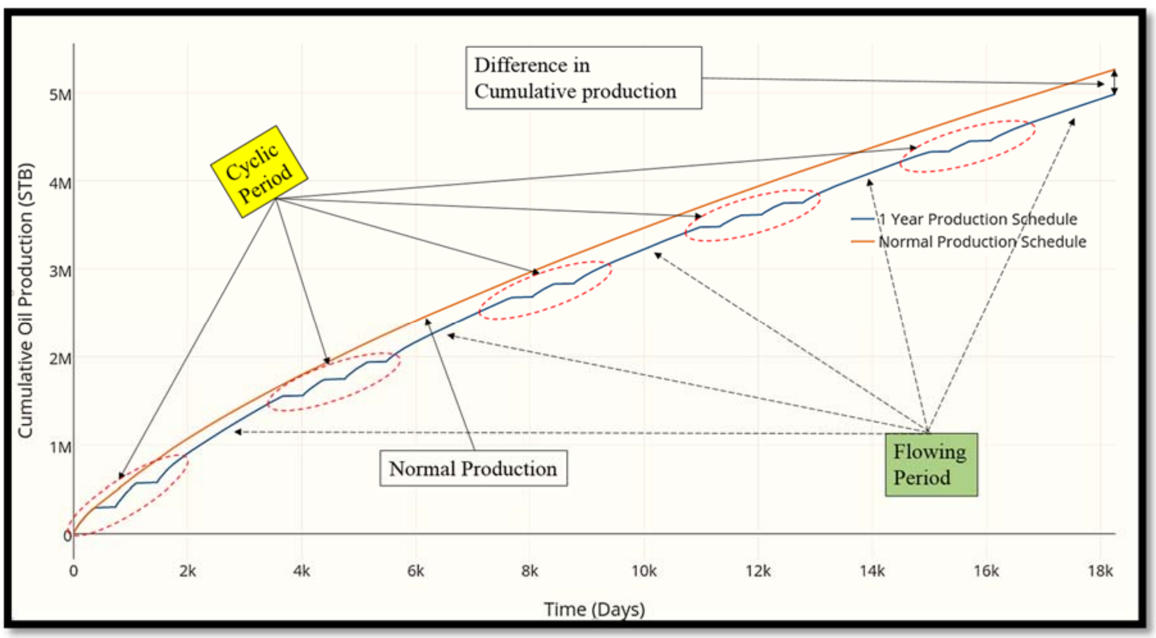


Figure 3.10. Cumulative oil production with 1-year schedule vs. Normal production.

In this case, it can be seen that the ultimate recovery with the normal production performs better than 1 Year-RCPS; in other words, the production increase that is observed after the shut-in period is not enough to overcome the loss or deferment of production during the shut-in period of 1 year.

A 2-week shut-in/production case is illustrated in Figure 3.11. During the 2 Week shut-in period, the number of cycles in the cyclic period is huge and to show them clearly an enlarged section of the first few years is shown in the Figure 3.12. Even though the ultimate recovery for the case described in this section is affected negatively by the shut-in/production cycles, there are several scenarios where the oil recovery increases by as much as 12% and are discussed in Section-4. This case was selected for simplifying the understanding of RCPS and how the shut-in/production cycles are applied.

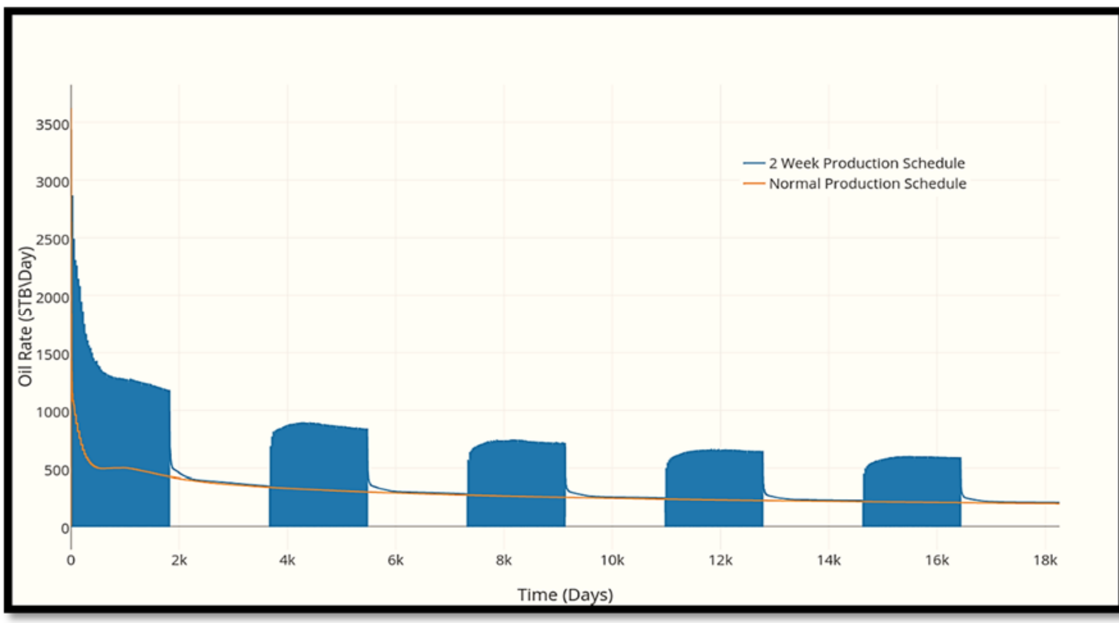


Figure 3.11. Oil Flow rate vs. Time for Normal and 2-week schedule.

In the next figure, an increase in the oil flowrate followed by 2-week shut-in can be seen; it is about three to four time more than the flowrate in normal production. Also, as soon as the well enters into flowing period, the flowrate matches with the normal production rate.

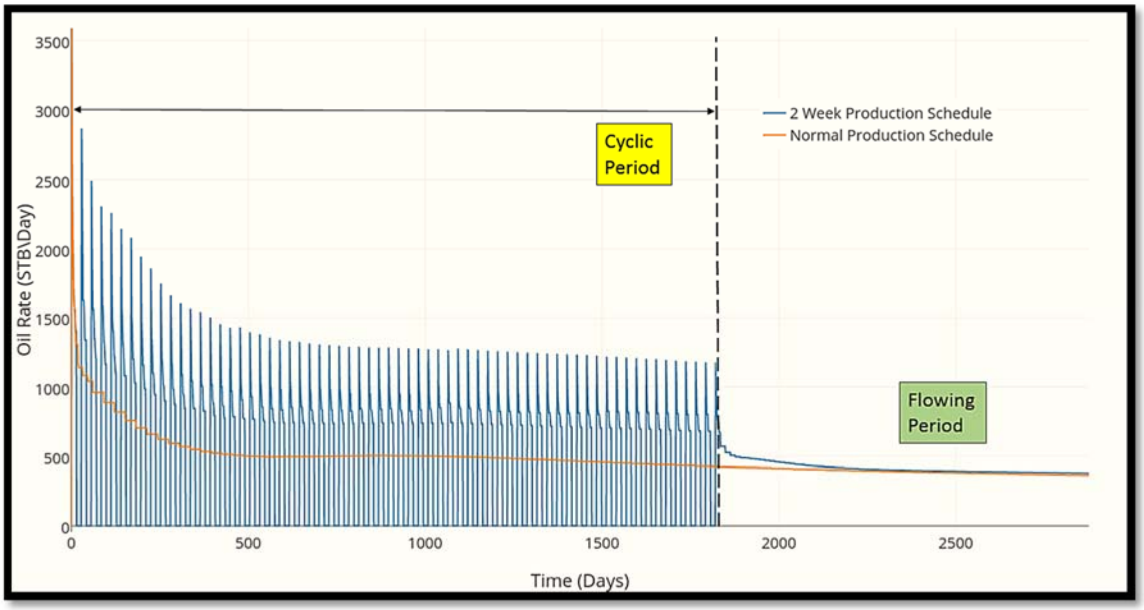


Figure 3.12. Zoomed section of first five years from Figure 3.11.

Similarly, the cumulative oil production and oil flow rate for 6-month RCPS, 1-month RCPS and 2-weeks RCPS are shown below along with a brief discussion about each one of them. As explained earlier about the RCPS, for 6-months schedule the shut-in/production cycles during the cyclic period (CP) are of 6 months duration followed by the flowing period (FP) during which the well operates at constant bottom-hole pressure of 250 psi. Figure 3.13 and 3.14 illustrate the cumulative oil production and oil flow rate respectively for 6-month RCPS. The increase in the oil rate followed by shut-in can be seen in Figure 3.13 and the impact of the same can also be seen on the cumulative oil production in Figure 3.14.

For 1-month and 2-weeks RCPS, the number of cycles during the cyclic period are a lot more than for 6-months which makes them appear very close to each other on the oil rate graph. In addition, this affects the cumulative oil production curve and the shut-in/production cycles being so small in duration needs a closer look on the graph to be identified and are marked by a red dotted circle on all the cumulative oil plots.

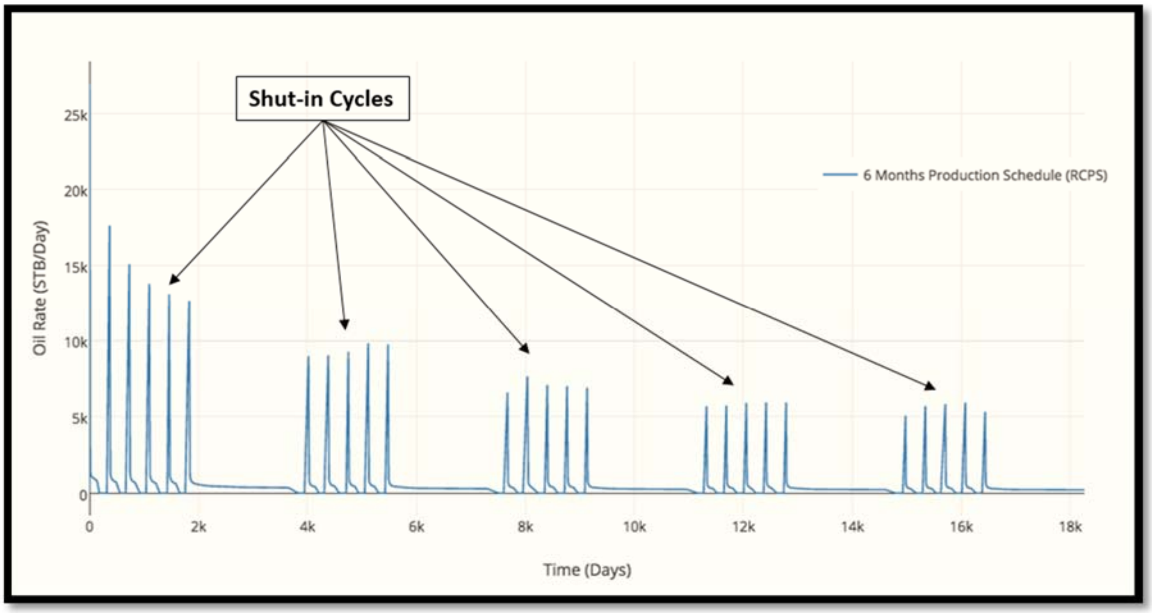


Figure 3.13. Oil Flow rate vs. Time for 6-months schedule.

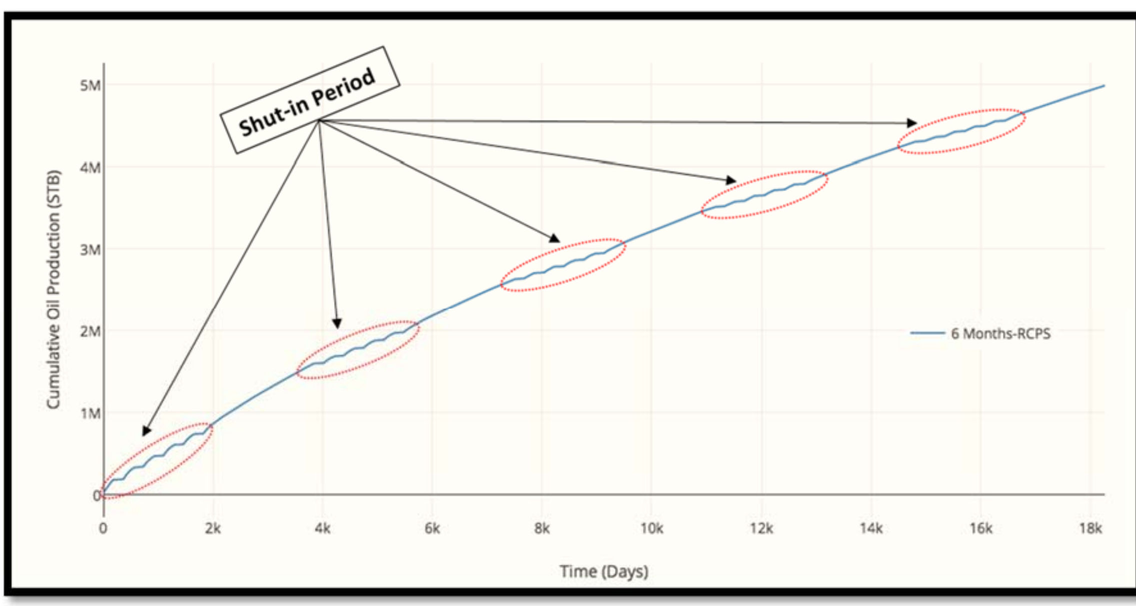


Figure 3.14. Cumulative oil production vs. Time for 6-months schedule.

Figure 3.15 and 3.16 illustrate the oil flow rate and cumulative oil for the 1-month RCPS respectively.

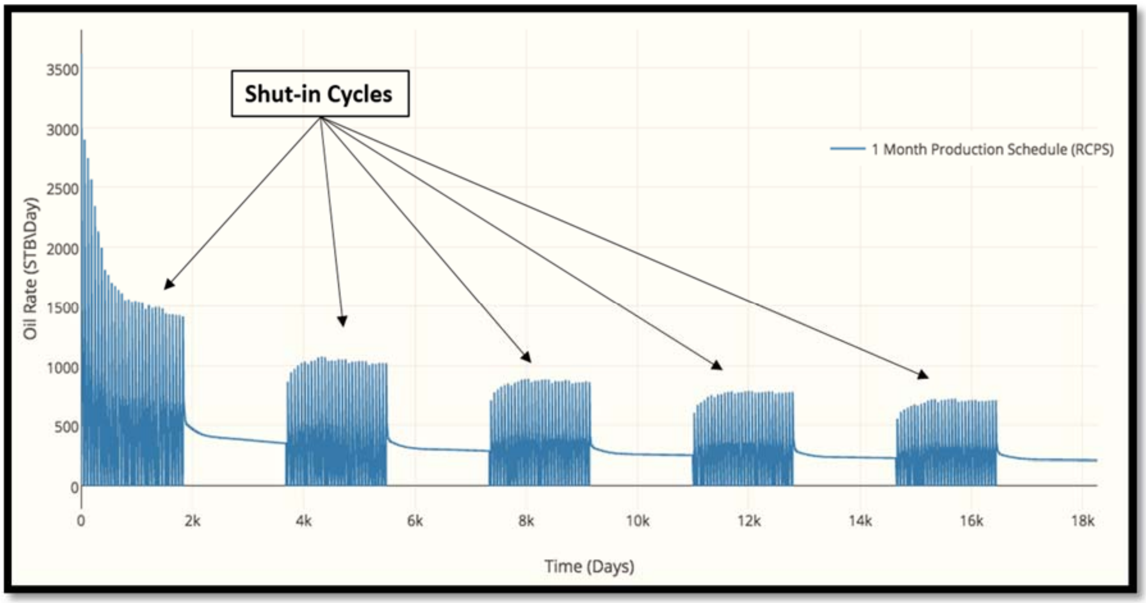


Figure 3.15. Oil Flow rate vs. Time for 1-month schedule.

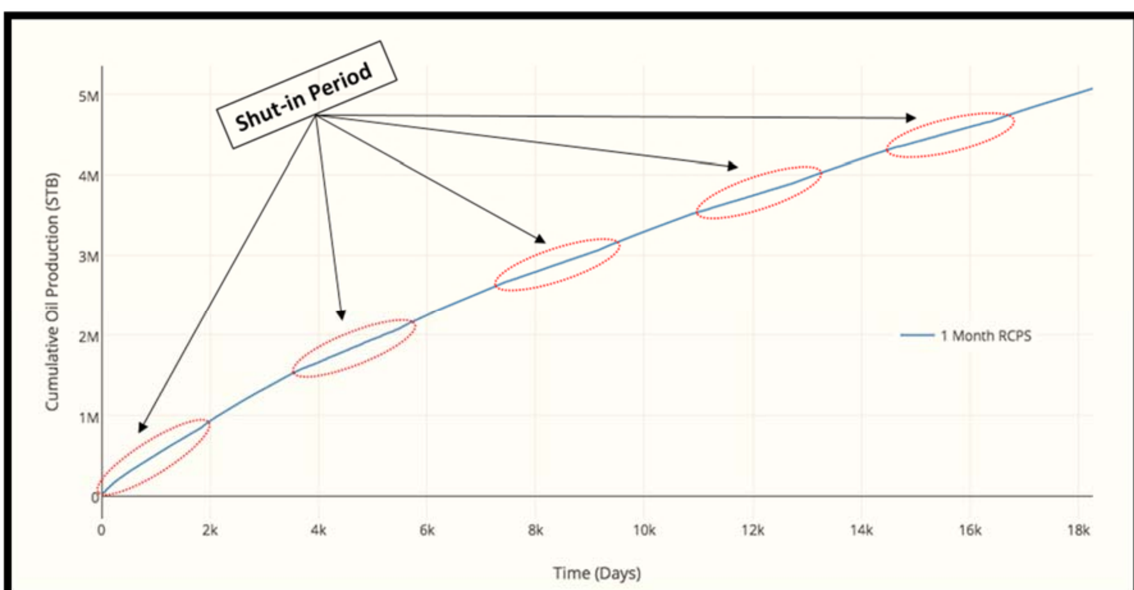


Figure 3.16. Cumulative oil production vs. Time for 1-month schedule.

Figure 3.17 and 3.18 illustrate the oil flow rate and cumulative oil for the 2-weeks RCPS respectively.

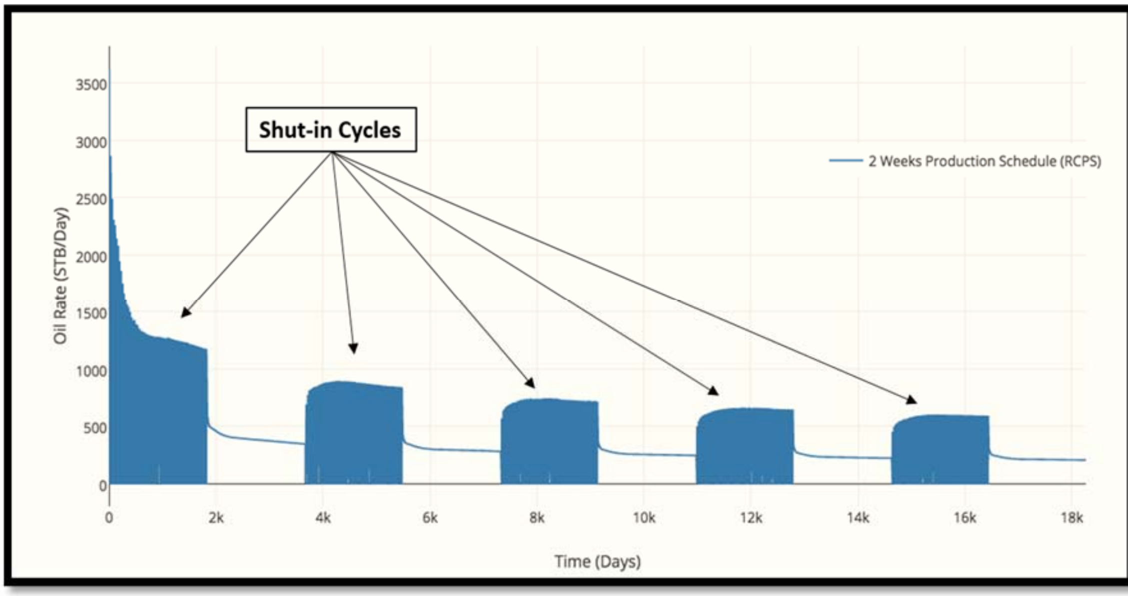


Figure 3.17. Oil Flow rate vs. Time for 2-weeks schedule.

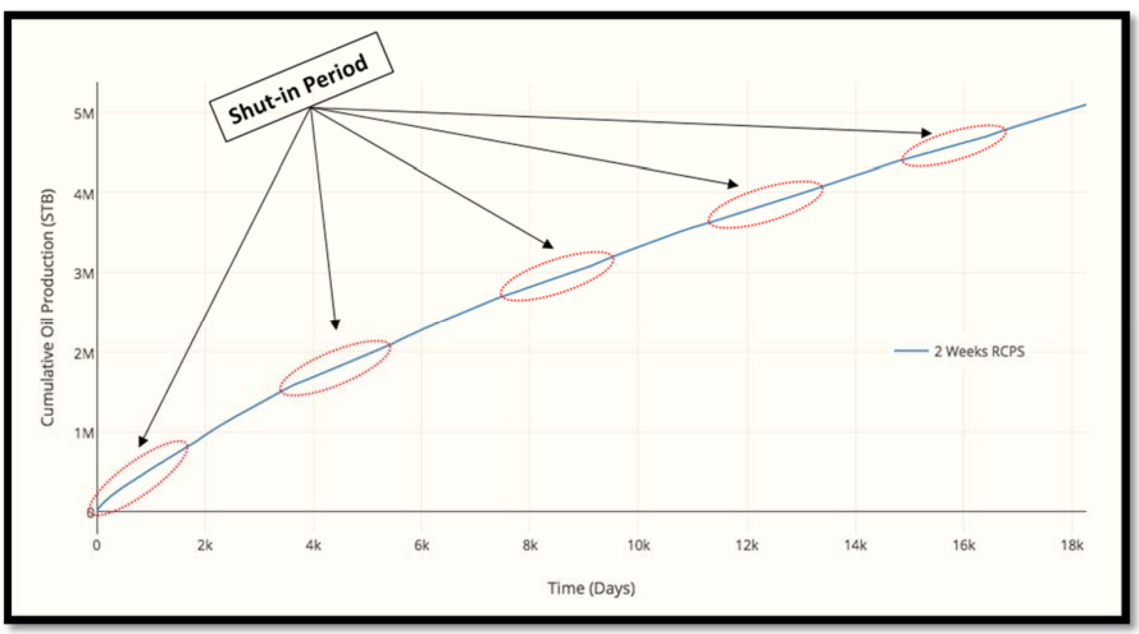


Figure 3.18. Cumulative oil production vs. Time for 2-weeks schedule.

3.3. PROCEDURE

This section details the procedure used in this study for both the models. It also presents all the cases created for this study.

3.3.1. Model with One Well. To analyze the impact of shut-in/production cycles over a varied range permeabilities, the reservoir permeability of the model was changed from 0.000001 md to 10 md. RCPS with all four shut-in periods simulated in each permeability case; Table 3.5 lists the permeability used in each case.

Table 3.6. Cases for model with one well.

Case	**Permeability**	**Case**	**Permeability**
Case 1	0.000001 md	**Case 5**	0.01 md
Case 2	0.00001 md	**Case 6**	0.1 md
Case 3	0.0001 md	**Case 7**	1.0 md
Case 4	0.001 md	**Case 8**	10.0 md

For case-1, the reservoir-permeability of the single well model is set to 0.000001 md and is simulated with all the shut-in/production cycles/RCPS as mentioned in section 3.2; the ultimate recovery with each shut-in/production period is graphed, and optimum production schedule is recognized. This process is repeated for all the other cases, and results for each case is discussed in section 4. The next section discusses about the procedure followed for the second model used in this study, five cases are built for the second model and are explained in detail.

3.3.2. Model with Two Wells. This model is used to analyze how the shut-in/production cycles can be applied in a multiple and interfering well scenario, in a way that production never comes to a complete halt.

In this model a miniature version of RCPS is simulated by having two neighboring wells with alternating shut-in periods when they are in the cyclic period; when well-1 is shut-in, well-2 is flowing and vice versa. This allows the production from one of the wells to occur at all times. Five different shut-in/production scenarios are simulated, they are listed in Table 3.6 and are further explained in the later sections.

Table 3.7. Cases for model with two wells.

Case	Permeability
Case 9	Both the wells are producing normally.
Case 10	Well-1 on cyclic production; Well-2 produces normally
Case 11	Both wells on same cyclic production schedule
Case 12	Both wells on cyclic production, but altering shut-in cycles
Case 13	Both wells on cyclic production, but altering shut-in periods

3.3.2.1 Case-9. In this case, both the wells are flowing normally at a constant bottom-hole pressure of 250 psi. This simulation can be linked with producing normally from a field with multiple wells, where all the wells are on continuous production.

3.3.2.2 Case-10. In this case, one well is kept on RCPS with a shut-in period of 1 month, and the other well is flowing continuously. This can be related with field scenario where only half of the wells are producing in cyclic shut-in pattern and the rest are flowing normally.

3.3.2.3 Case-11. In this case, both the wells are kept on RCPS with same period; hence, both the wells open and shut at the same time. This can be related to a field scenario where all the wells are kept on cyclic production pattern with the same cycles, hence when the shut-in period approaches; all the wells are shut and there is no production.

3.3.2.4 Case-12. In this case, both the wells are kept on cyclic production pattern with alternating shut-in cycles. During this cyclic period, the first well is flowing and the second well is shut-in. This can be related to a field scenario which is most favorable for the operator; half of the wells are shut, and the other half are flowing during the cyclic period. This also ensures that the field is always producing with the advantage of utilizing the shut-in\production pattern.

3.3.2.5 Case-13. In this case, both the wells are kept on cyclic production pattern with alternating shut-in\production periods. When the first well is in the cyclic period, the other well is kept in the flowing period. During the first five years, well-1 is kept on a cyclic production pattern, and well-2 flows normally; this procedure is repeated for 50 years keeping one of the wells on cyclic production pattern all the time.

4. RESULTS AND ANALYSIS

This section presents the results and analysis from all the reservoir simulation cases mentioned in Section 3.3.1 and 3.3.2. Results are shown in the form of normalized recovery plot. The x-axis on this plot indicates the different production schedules and the y-axis indicates the normalized recovery. Equation 2 is used for calculating the normalized recovery in each case:

$$(\text{Normalized Recovery})_{\mathbf{n}} = \frac{(\text{EUR})_{\mathbf{n}}}{(\text{EUR})_{\text{Normal Production}}} \qquad (2)$$

Where,

- $(\text{EUR})_{\text{Normal Production}}$ = Estimated Ultimate Recovery for normal production.
- $(\text{EUR})_{\mathbf{n}}$ = Estimated Ultimate Recovery for the n^{th} schedule. (n = 2-weeks, 1-month, 6-months, 1-year)

Hence, all the cases where normalized recovery is more than ‘1’ signifies an improvement in the ultimate recovery. Also, this section does not include the hydrocarbon cumulative and flowrate graphs as the main focus of this research was to study the impact of shut-in cycles on the ultimate recovery.

4.1. CASE-1

This case involves simulation with single-well model and having the reservoir-permeability of 0.000001 md. Figure 4.1 shows normalized recovery plot for Oil, Gas, and Water.

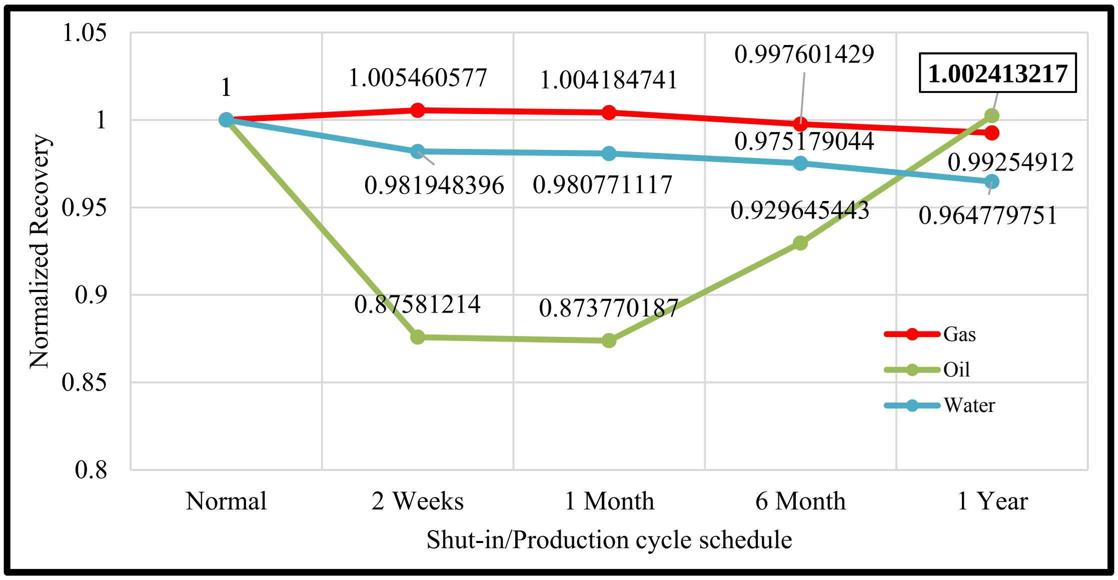


Figure 4.1. Normalized Recovery for 0.000001 md.

The ultimate oil recovery is slightly improved with 1 Year-RCPS; the increase is 0.2%. Also, the ultimate recovery of gas increased for 2 Weeks and 1 Month RCPS by 0.5% and 0.4 % respectively. The water decreased in all other production schedules by as much as 8% in the most optimum case. While the improvement in the oil recovery is very small, it should be noted that the flowing time of well was reduced by 12.5 years and the well was able to match the production with a normally flowing well. This indicates that RCPS did not harm the recovery and reduced the water production.

4.2. CASE-2

This case involves simulation with single-well model and having the reservoir-permeability of 0.00001 md. Figure 4.2 shows normalized recovery plot for Oil, Gas, and Water.

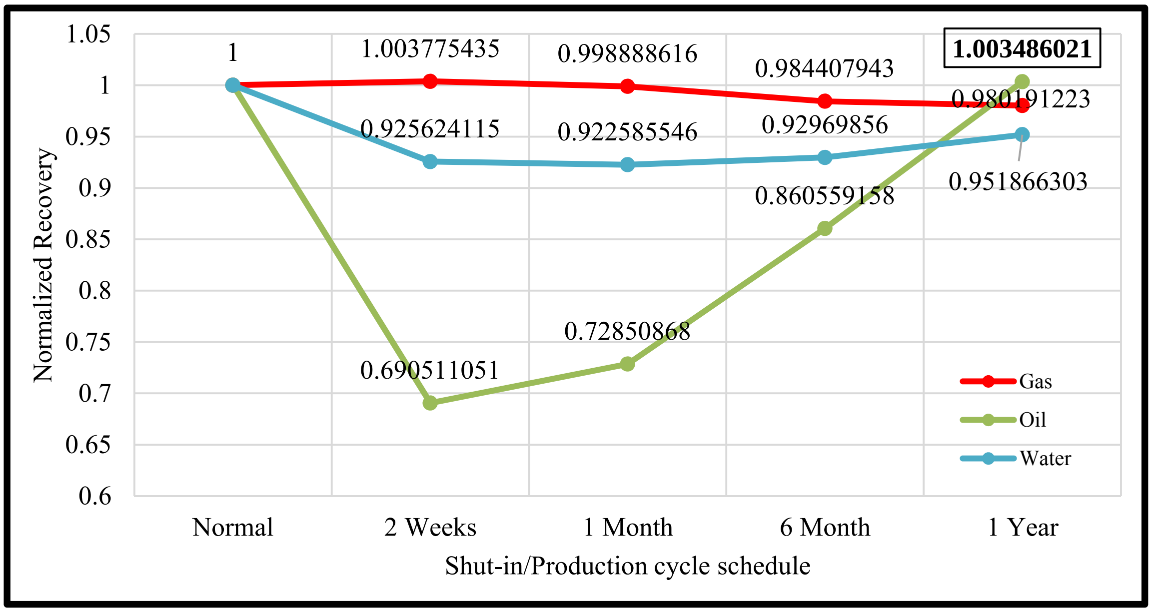


Figure 4.2. Normalized Recovery for 0.00001 md.

The ultimate oil recovery is slightly improved with 1 Year-RCPS; the increase is 0.3%. Also, the ultimate recovery water decreased in all other production schedules. The results in this case are similar to the previous case. The well was able to match the production with the normal production schedule, which indicates that RCPS did not harm the recovery.

4.3. CASE-3

This case involves simulation with single-well model and having the reservoir-permeability of 0.0001 md. Figure 4.3 shows normalized recovery plot for Oil, Gas, and Water.

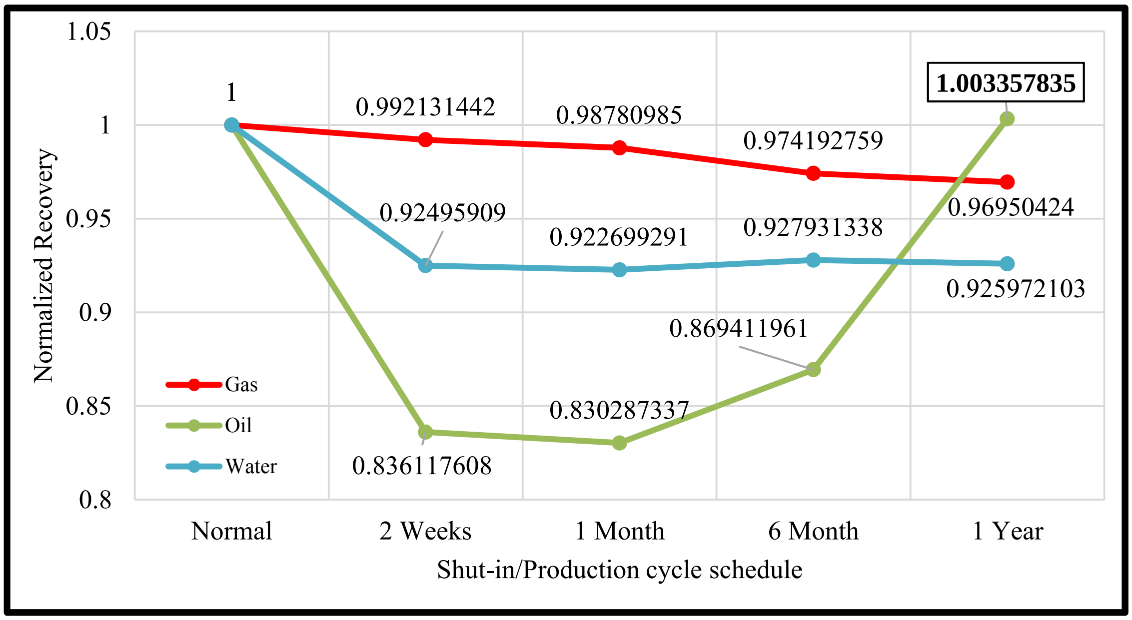


Figure 4.3. Normalized Recovery for 0.0001 md.

The ultimate oil recovery is improved by 0.3 % with 1 Year-RCPS. In addition, the ultimate recovery of gas and water decreased in all other production schedules. While the improvement in the oil recovery is very small, it should be noted that the flowing time of well was reduced by 12.5 years. The well was able to match the production with the normal production schedule; which indicates that RCPS did not harm the recovery. Also, the water production was reduced in all the cases by almost 8%.

4.4. CASE-4

This case involves simulation with single-well model and having the outer-permeability of 0.001 md. Figure 4.4 shows normalized recovery plot for Oil, Gas, and Water.

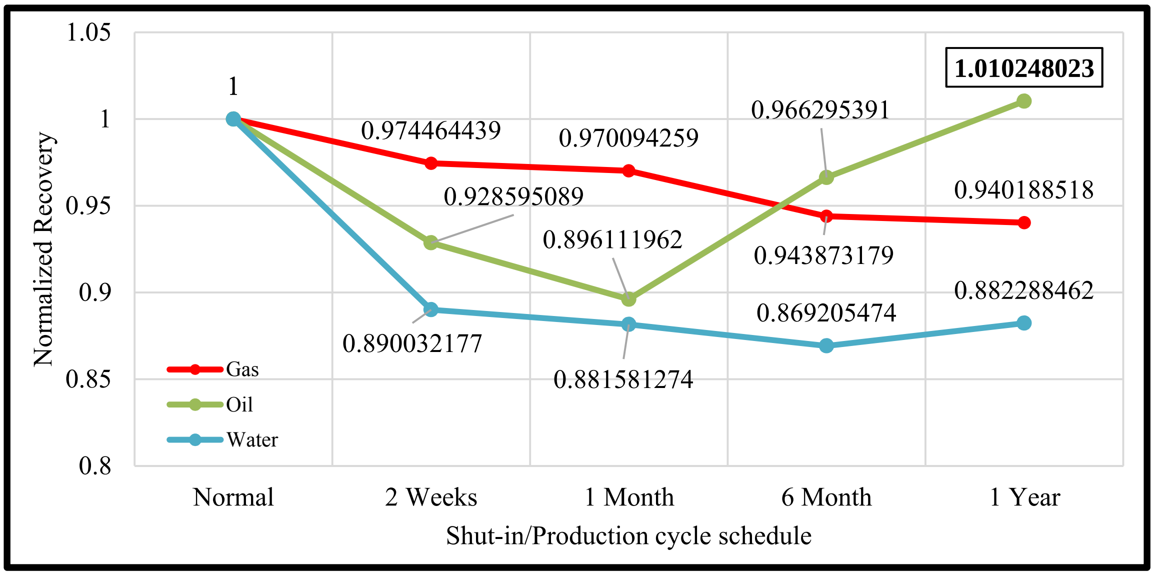


Figure 4.4. Normalized Recovery for 0.001 md.

The improvements observed in this case are very similar to the last one, the observed gain in oil production is 1.02% for 1-year schedule. Hence, as concluded from literature, the presence of free gas does help in improving the oil recovery although, the production gain is very small. The gas production is down by about 3%, and water production is reduced by 10-13 %.

4.5. CASE-5

This case involves simulation with single-well model and having the reservoir permeability of 0.01 md. Figure 4.5 shows normalized recovery plot for Oil, Gas, and Water.

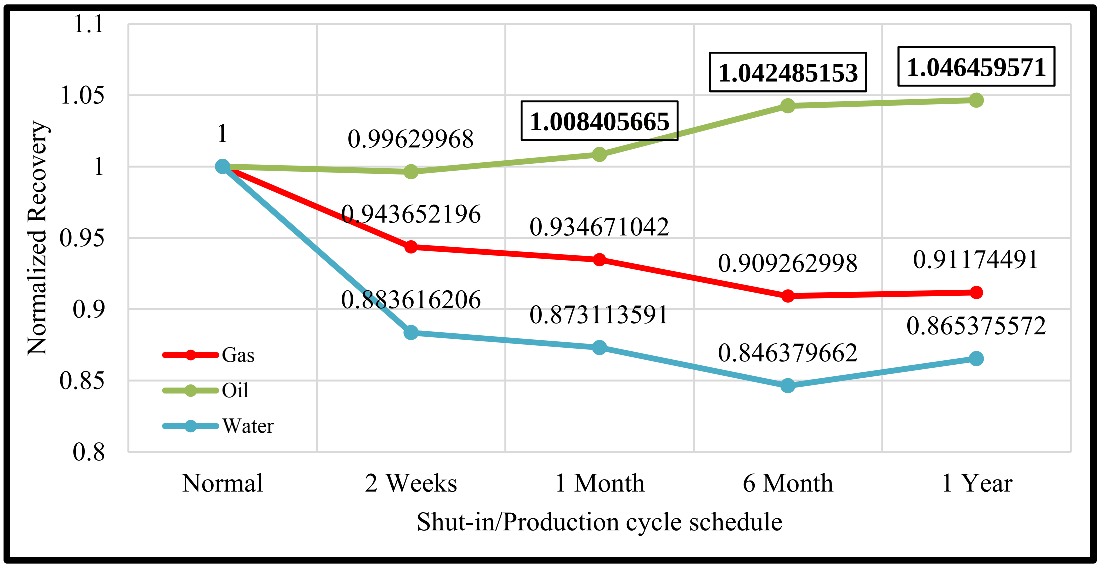


Figure 4.5. Normalized Recovery for 0.01 md.

A considerable increase in oil recovery is observed in this case as the 6-month and one year shut-in cases increased the recovery by about 4.2 % in and 4.6%, respectively. The gas production goes down by about 9%; as expected in saturated reservoirs. It can also be observed that the water production is significantly reduced; about 15% similar to prior studies cited in the literature. Longer shut-in period schedules perform better than shorter ones; this can be explained by the fact that pressure buildup takes a longer time in low permeability reservoirs than in conventional reservoirs.

4.6. CASE-6

This case involves simulation with single-well model and having the reservoir permeability of 0.1 md. Figure 4.6 shows normalized recovery plot for Oil, Gas, and Water.

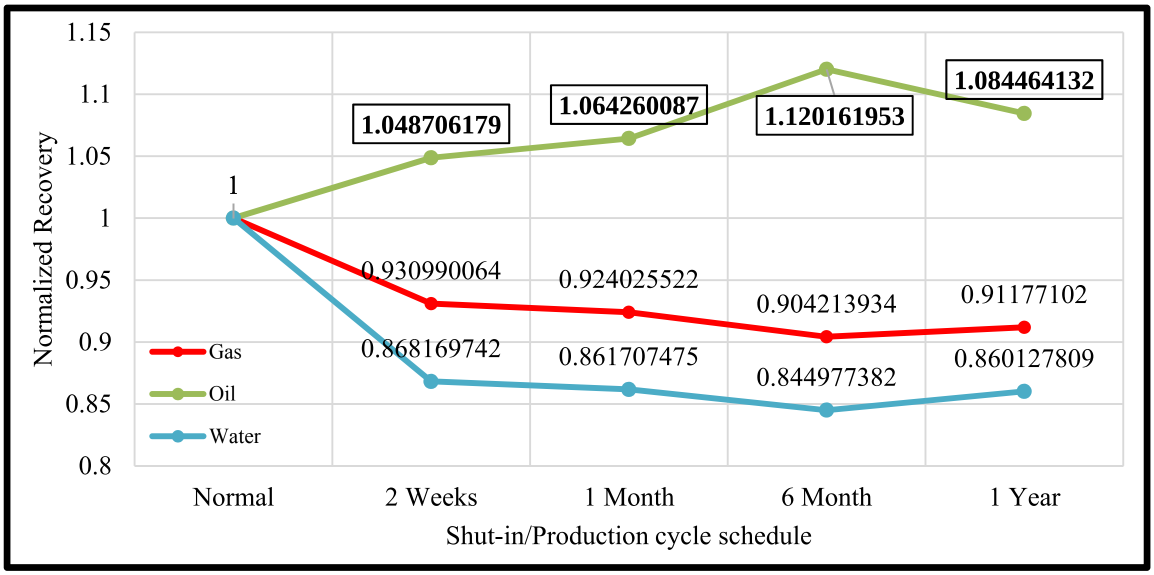


Figure 4.6. Normalized Recovery for 0.1 md.

In this case, RCPS improves the oil recovery in all the schedules along with decreasing the water production significantly. The oil production is increased by almost 12 %, and the gas production is reduced by about 10%. At this point, it can be concluded shut-in cycles, when applied systematically, can improve the ultimate recovery of oil and reduce the water production.

4.7. CASE-7

This case involves simulation with single-well model and having the outer-permeability of 1 md. Figure 4.7 shows normalized recovery plot for Oil, Gas, and Water.

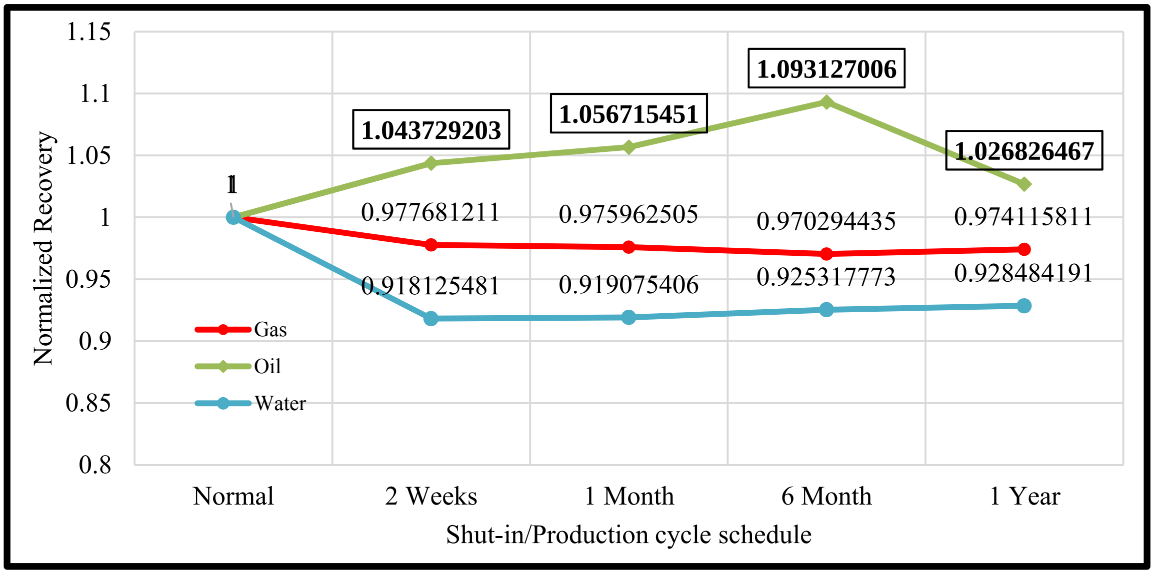


Figure 4.7. Normalized Recovery for 1 md.

The same result is observed in this case as well, gas production is reduced only by 2.5%, and this can be because of the higher permeability. Oil recovery is improved by almost 9.3%. It can be concluded that as we approach higher permeability scenarios, the reduction in gas production is not as much as low permeability cases because of better vertical communication in the reservoir; this allows the gas to travel towards the wellbore more freely.

4.8. CASE-8

This case involves simulation with single-well model and having the outer-permeability of 10 md. Figure 4.8 shows normalized recovery plot for Oil, Gas, and Water.

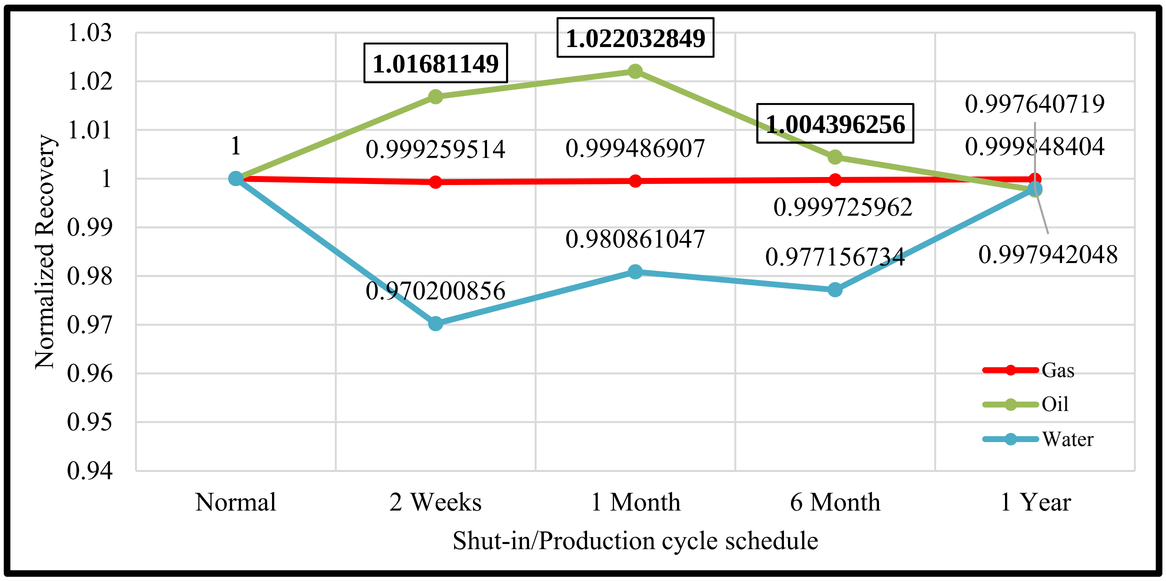


Figure 4.8. Normalized Recovery for 10 md.

Improvement in oil production is still seen but is less when compared with low-permeability reservoirs. The highest improvement was about 2.2% in the 1-month shut-in period; while the gas production is almost the same as normal production.

4.9. MODEL WITH TWO WELLS

This case involves simulation with the two-well model, the reservoir permeability of the model is set to 0.01md, and the shut-in schedule is 1 month. Details about the procedure involved in this simulation were mentioned in section 3.2.2. The selection of the permeability and shut-in period was done considering the most practical\ideal case from the industry standpoint. Normalized recovery plots are shown in Figure 4.9 for all the cases.

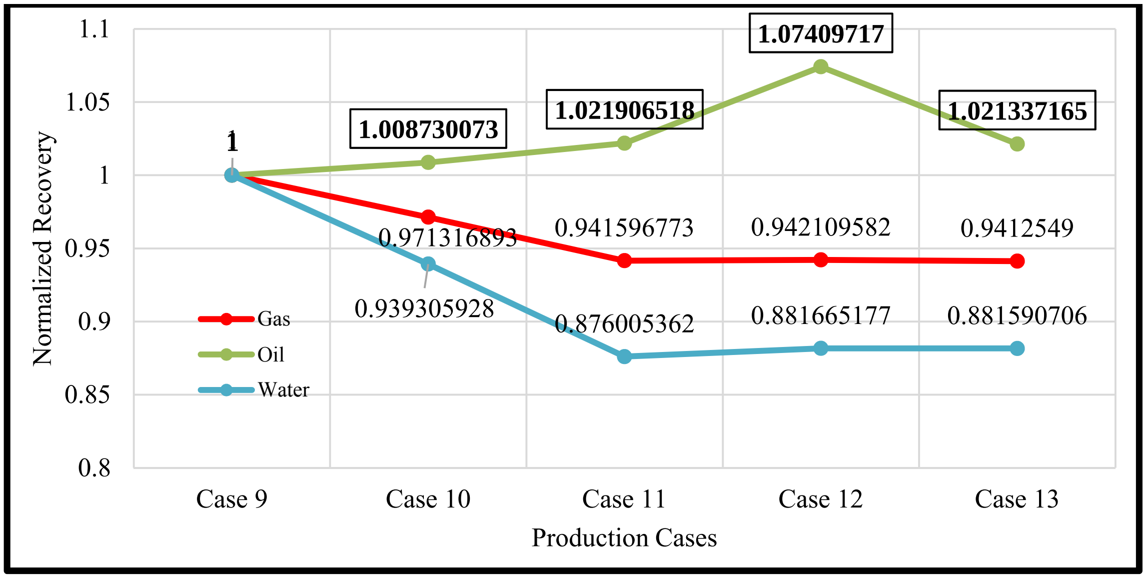


Figure 4.9. Normalized Recovery for all cases in model with 2 Wells.

As shown, the ultimate recovery of oil was improved the most in Case-12; which is the most practical and simulates a scenario involving shutting in half the wells at a time while keeping the rest open and then altering this procedure by shutting in the open wells and opening the shut-in wells. One of the limitations of this model is the location of the well; the RCPS with altering cycles was applied to wells next to each other and should be applied when considering the design.

4.10. SUMMARY OF ALL THE CASES

This section summarizes the results for all the simulation cases, Normalized recovery for oil is shown in Table 4.1 followed by gas and water normalized recoveries in Table 4.2 and Table 4.3 respectively.

Table 4.1. Normalized Oil Recovery for Case-1 to Case-8.

Permeability (md)	Normal	2-Weeks	1 Month	6 Months	1 Year
0.000001	1	0.875812	0.87377	0.929645	1.002413
0.00001	1	0.690511	0.728509	0.860559	1.003486
0.0001	1	0.836118	0.830287	0.869412	1.003358
0.001	1	0.928595	0.896112	0.966295	1.010248
0.01	1	0.9963	1.008406	1.042485	1.04646
0.1	1	1.048706	1.06426	1.120162	1.084464
1	1	1.043729	1.056715	1.093127	1.026826
10	1	1.016811	1.022033	1.004396	0.997641

Table 4.2. Normalized Gas Recovery for Case-1 to Case-8.

Permeability (md)	Normal	2-Weeks	1 Month	6 Months	1 Year
0.000001	1	1.005461	1.004185	0.997601	0.992549
0.00001	1	1.003775	0.998889	0.984408	0.980191
0.0001	1	0.992131	0.98781	0.974193	0.969504
0.001	1	0.974464	0.970094	0.943873	0.940189
0.01	1	0.943652	0.934671	0.909263	0.911745
0.1	1	0.93099	0.924026	0.904214	0.911771
1	1	0.977681	0.975963	0.970294	0.974116
10	1	0.99926	0.999487	0.999726	0.999848

Table 4.3. Normalized Water Recovery for Case-1 to Case-8.

Permeability (md)	Normal	2-Weeks	1 Month	6 Months	1 Year
0.000001	1	0.98195	0.98077	0.97518	0.96478
0.00001	1	0.92562	0.92259	0.9297	0.95187
0.0001	1	0.92496	0.9227	0.92793	0.92597
0.001	1	0.89003	0.88158	0.86921	0.88229
0.01	1	0.88362	0.87311	0.84638	0.86538
0.1	1	0.86817	0.86171	0.84498	0.86013
1	1	0.91813	0.91908	0.92532	0.92848
10	1	0.9702	0.98086	0.97716	0.99794

5. CONCLUSION AND FUTURE WORK

This section summarizes the advantages and weaknesses of the shut-in\production cycles on low permeability reservoirs. It also discusses the potential areas for future work by suggesting how this model and shut-in method can be improved in the second section.

5.1. CONCLUSION

The conclusions of this research are listed below:

1. In low-permeability reservoirs, shut-in cycles can improve the ultimate recovery of oil if applied systematically.
2. Longer shut-in times are required in very low-permeability reservoirs to notice improvements in the oil recovery.
3. Shut-in/production cycles greatly reduce water production and is due to gravity segregation of water from the fracture network during the shut-in period.
4. The improvement in recovery is only seen in saturated reservoirs, for under-saturated reservoirs the recovery of hydrocarbons has no impact; but the water production is greatly reduced.
5. This technique can be applied in an oil-field while having continuous production; this can be done by shutting in half or the desired number of wells at once; keeping the rest flowing and then alternating this process.

5.2. FUTURE WORK

The following work is suggested for future research:

1. This simulation model does not consider natural fissures or stress dependent fractures; hence, this can be added in a future modelling study.

2. This modelling study considered black oil fluid properties. Using real fluid data in a compositional model may help to extend the conclusions from this study.
3. This modelling study considered a single well and two wells within a large drainage area. Expanding the number of wells within the drainage area to emulate pad development and detailing the well interference during cycling would be a potentially valuable addition.

APPENDIX

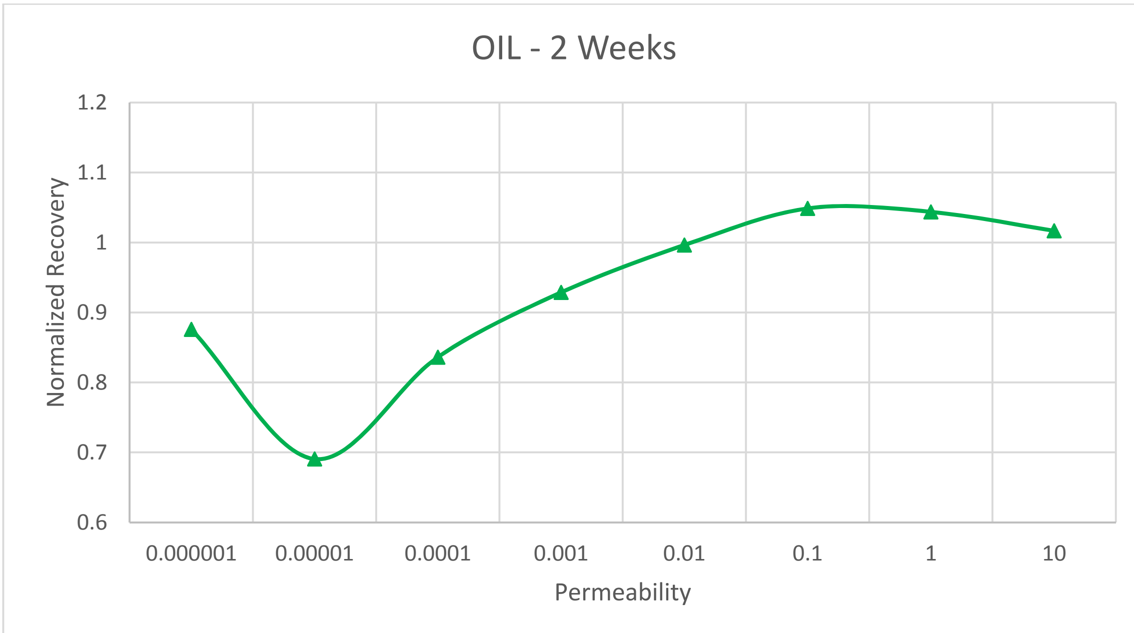


Figure 1. Effect of 2-Weeks RCPS on Oil Recovery for 0.000001md to 10md.

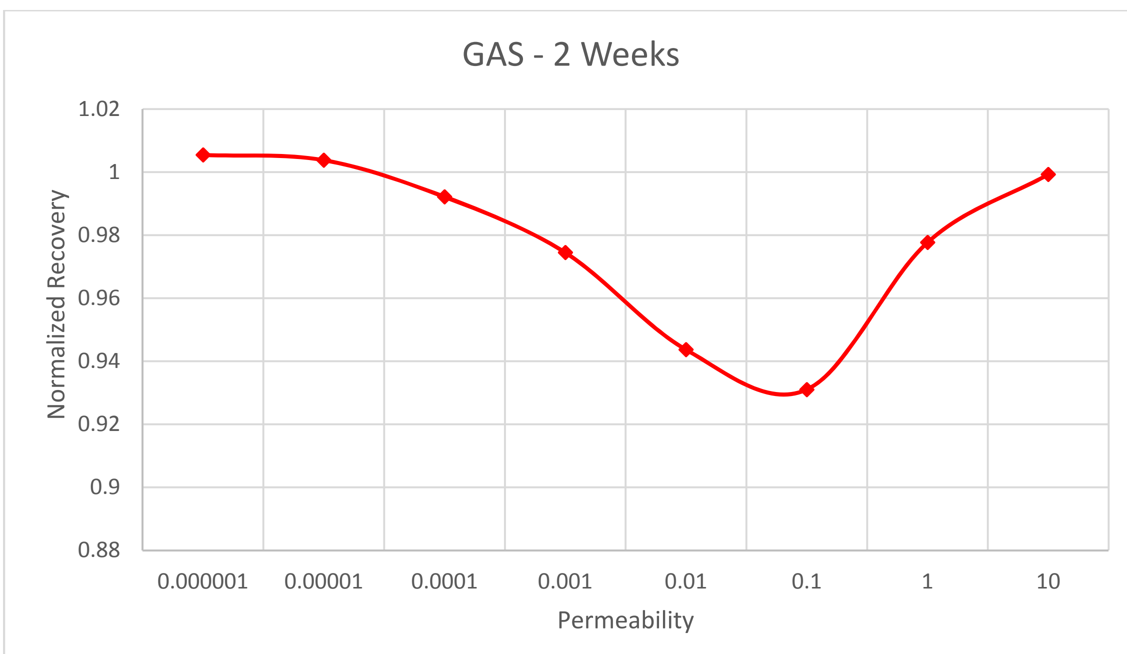


Figure 2. Effect of 2-Weeks RCPS on Gas Recovery for 0.000001md to 10md.

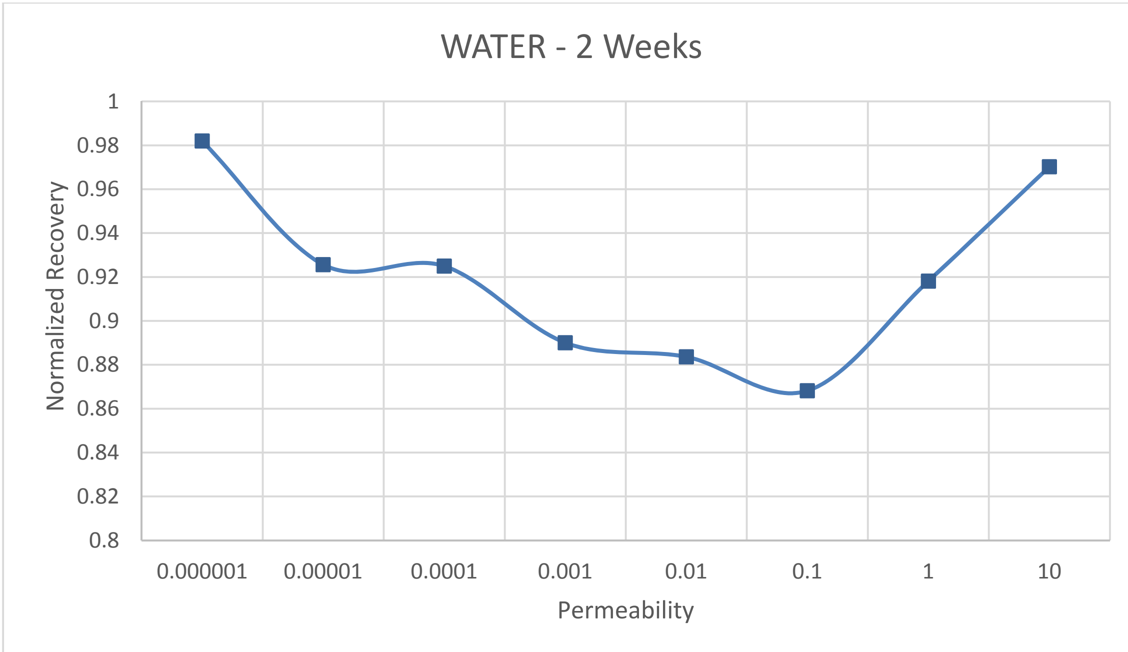


Figure 3. Effect of 2-Weeks RCPS on Water Recovery for 0.000001md to 10md.

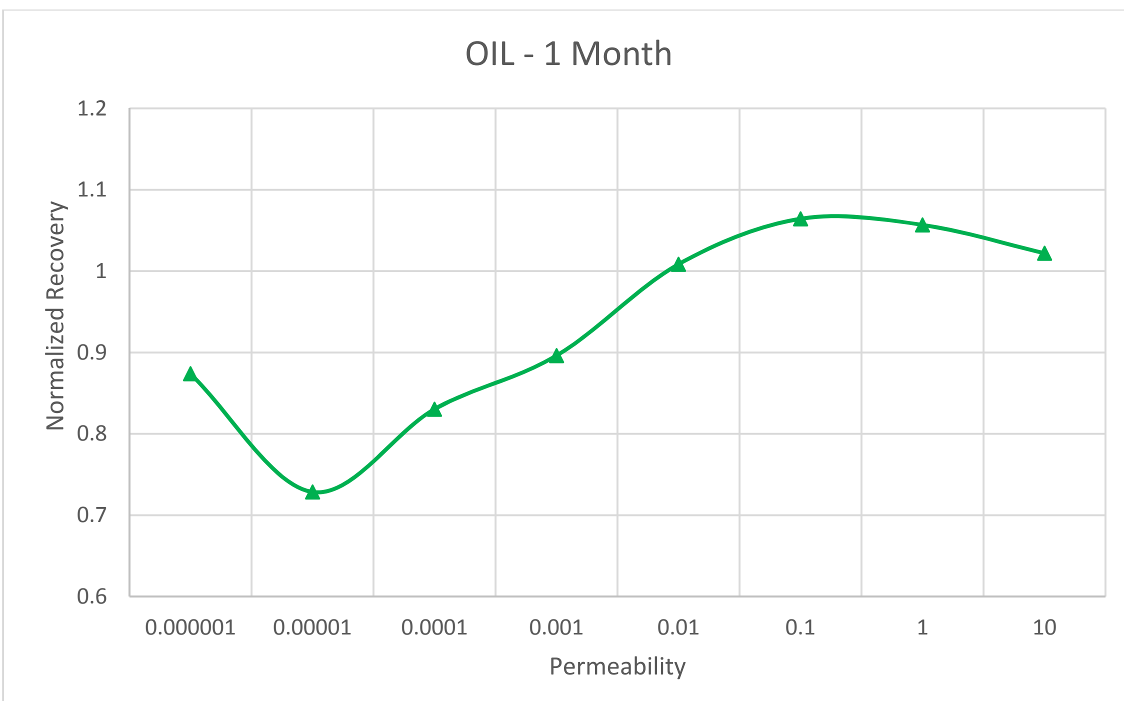


Figure 4. Effect of 1-Month RCPS on Oil Recovery for 0.000001md to 10md.

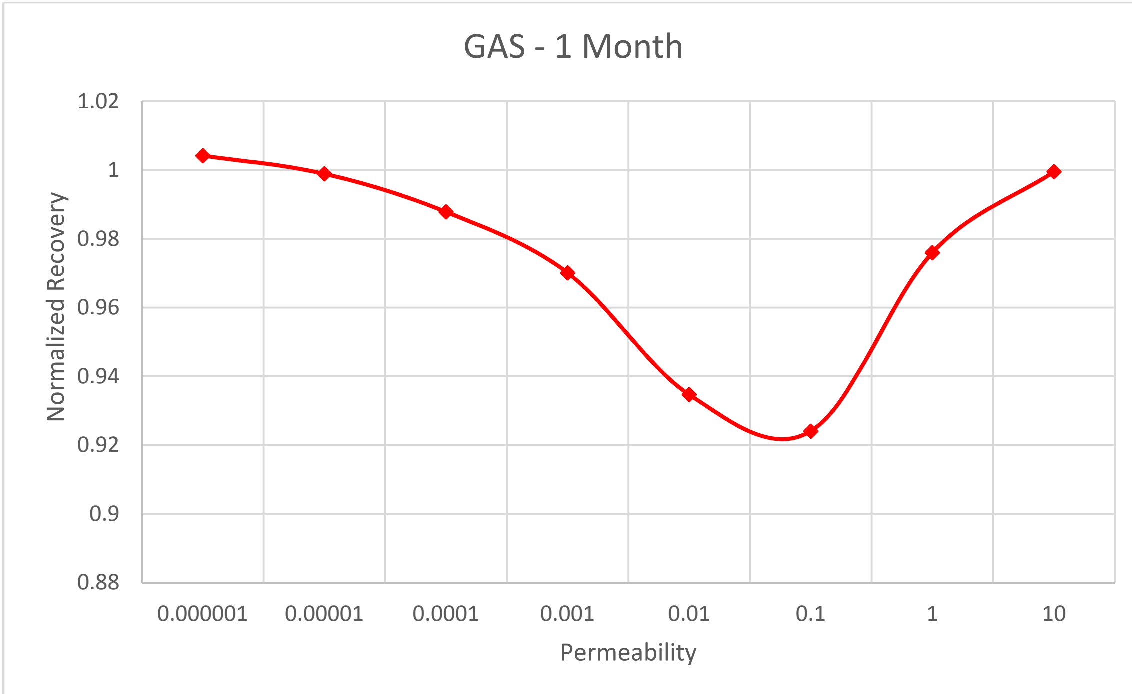


Figure 5. Effect of 1-Month RCPS on Gas Recovery for 0.000001md to 10md.

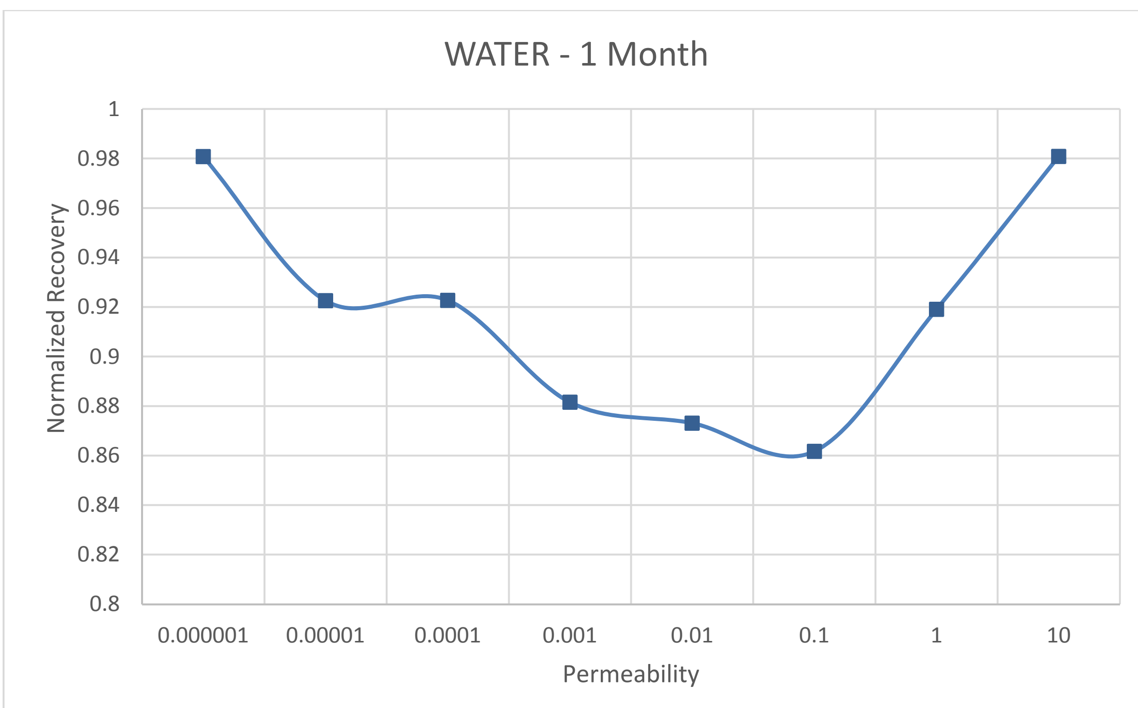


Figure 6. Effect of 1-Month RCPS on Water Recovery for 0.000001md to 10md.

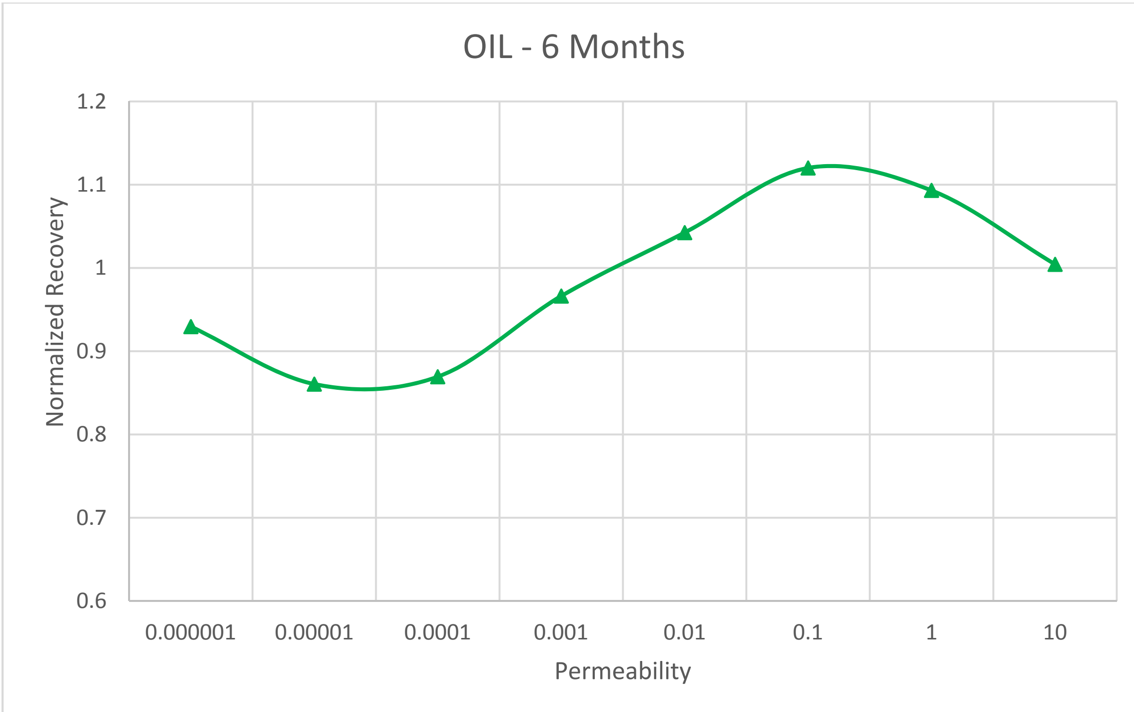


Figure 7. Effect of 6-Month RCPS on Oil Recovery for 0.000001md to 10md.

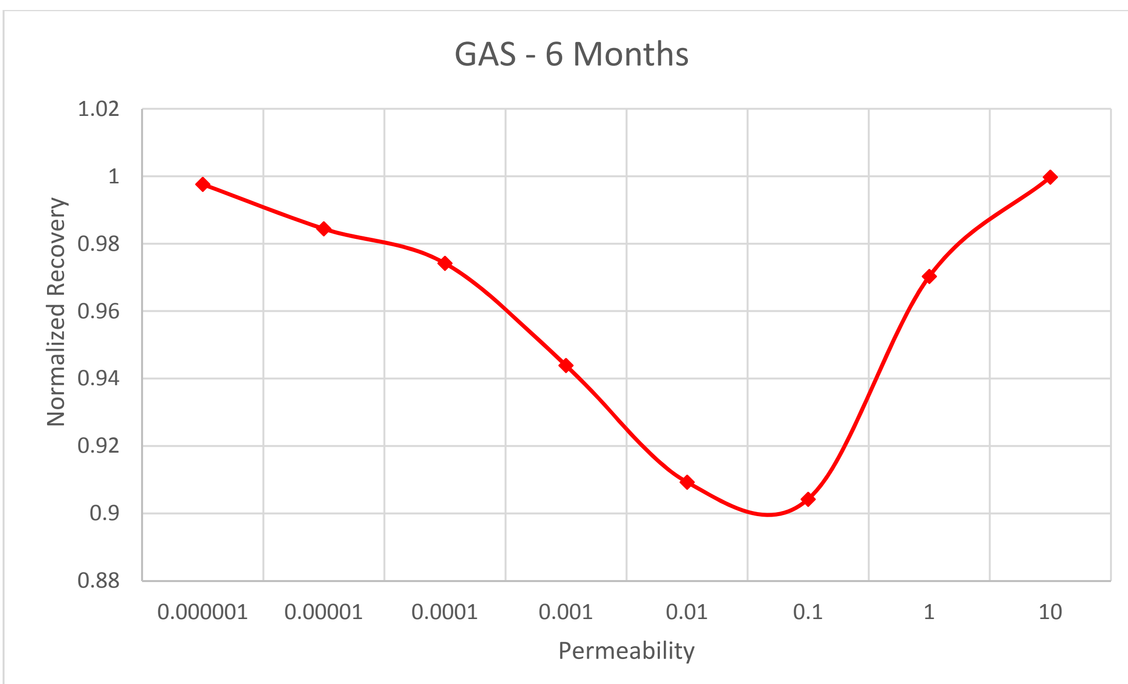


Figure 8. Effect of 6-Months RCPS on Gas Recovery for 0.000001md to 10md.

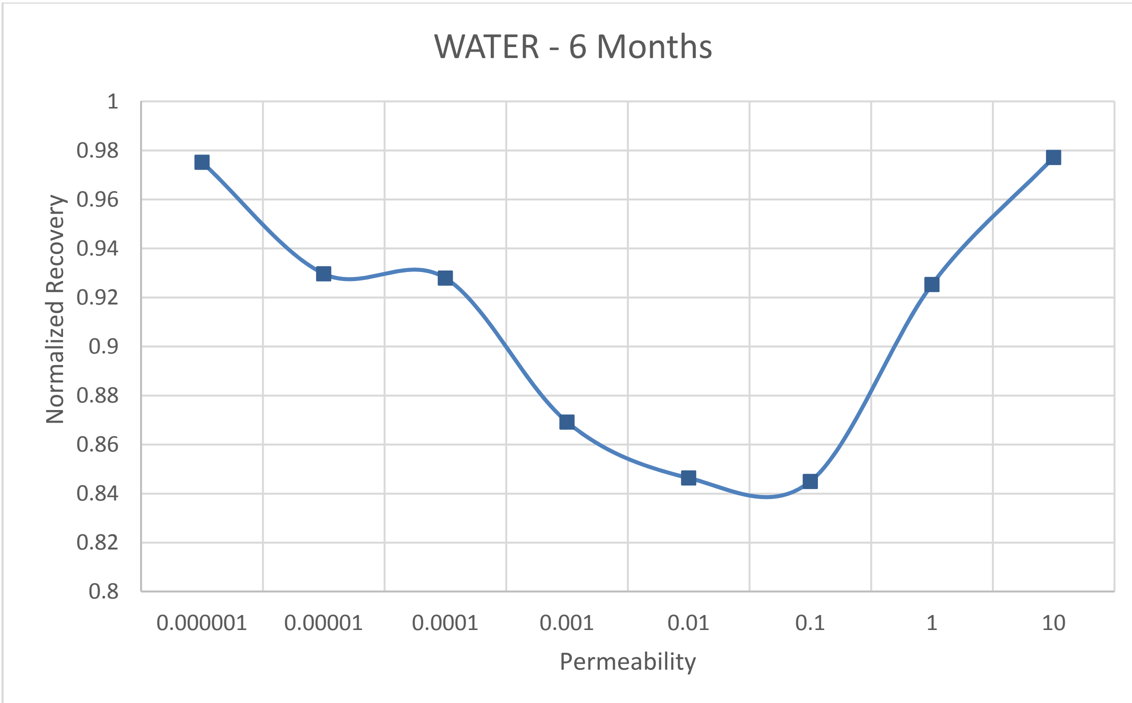


Figure 9. Effect of 6-Months RCPS on Water Recovery for 0.000001md to 10md.

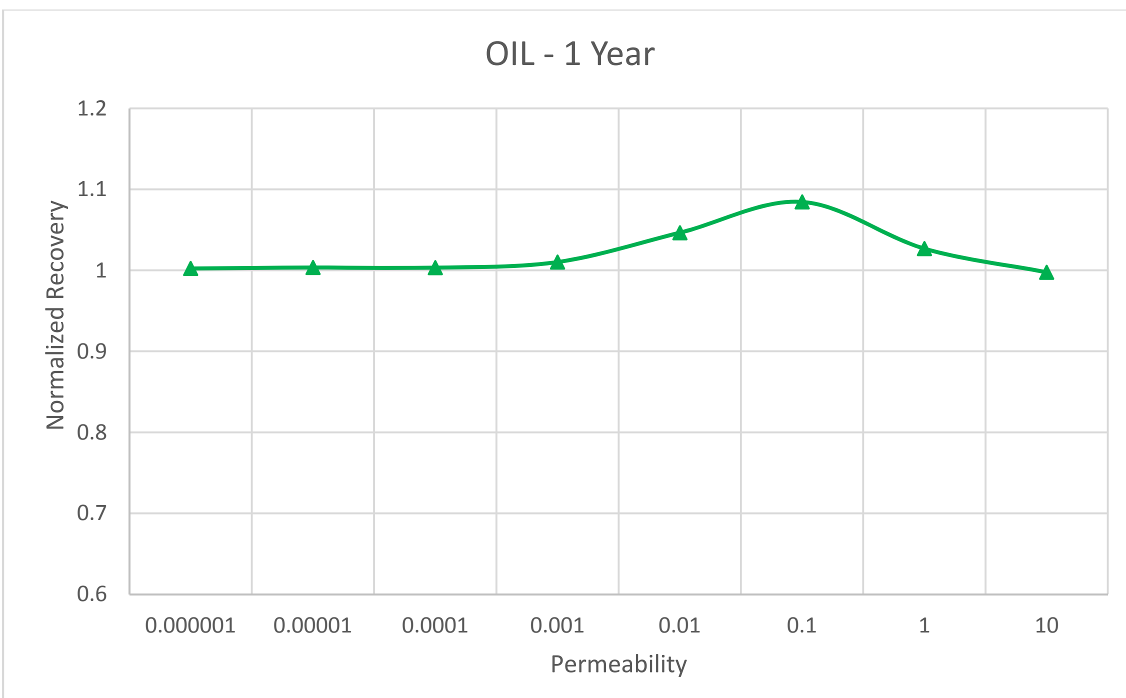


Figure 10. Effect of 1-Year RCPS on Oil Recovery for 0.000001md to 10md.

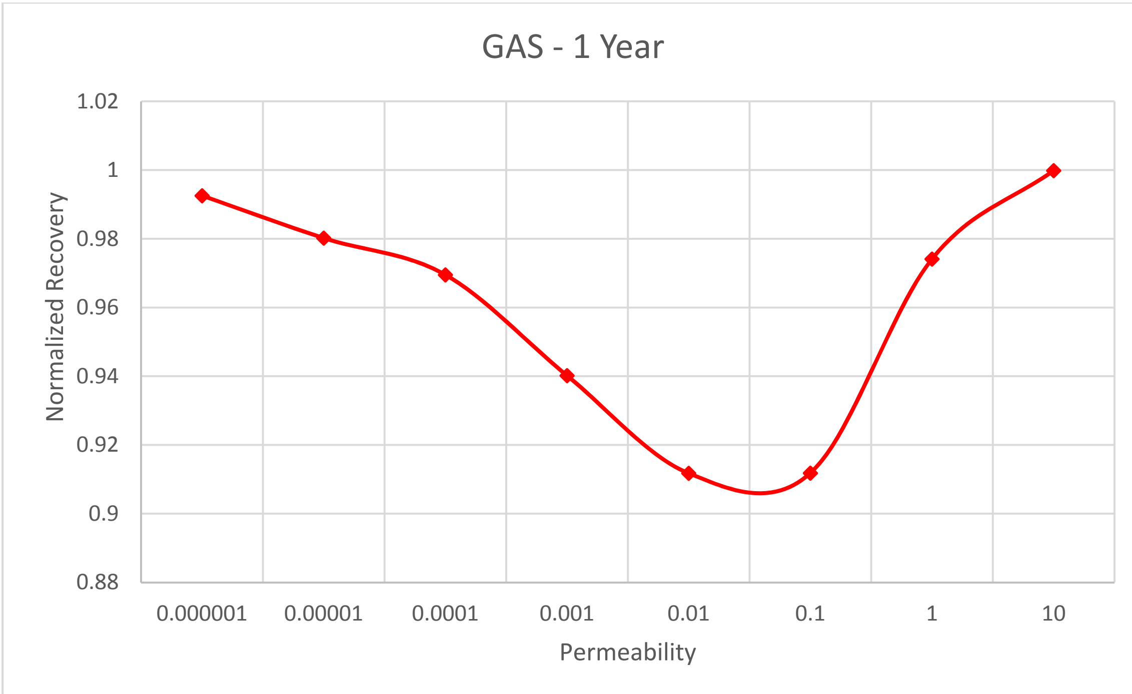


Figure 11. Effect of 1-Year RCPS on Gas Recovery for 0.000001md to 10md.

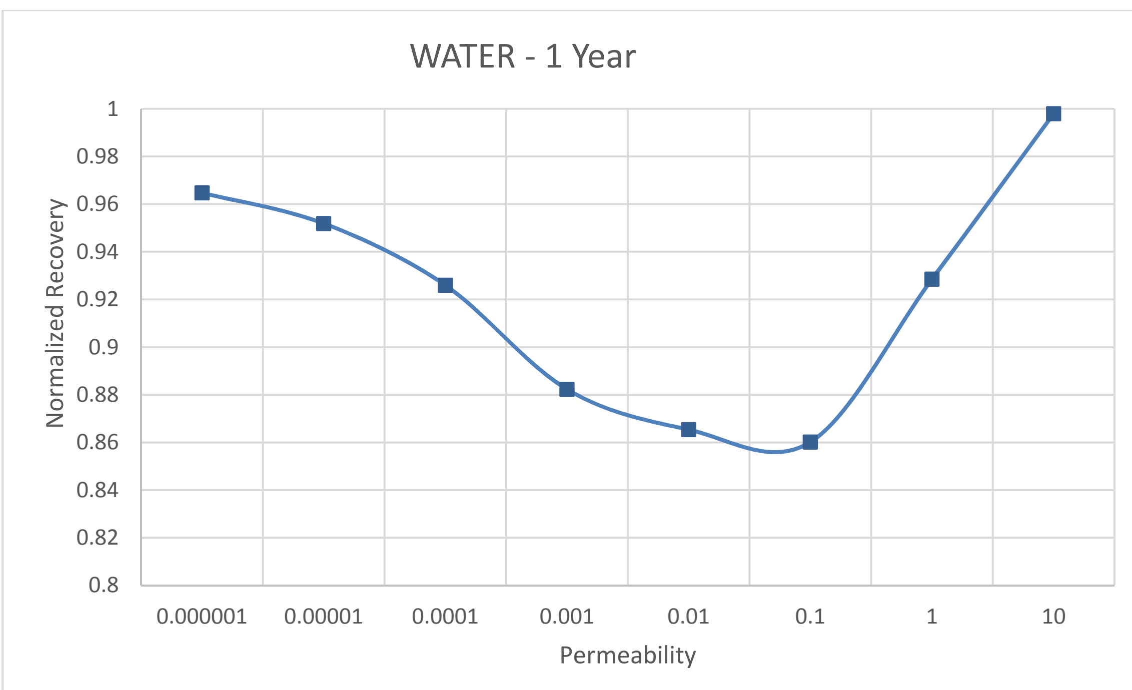


Figure 12. Effect of 1-Year RCPS on Water Recovery for 0.000001md to 10md.

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